CALIFORNIA
ENERGY
COMMISSION

Market Assessment of Combined Heat and Power in the State of California

(REPORT DATE: JULY, 1999)

CONSULTANT REPORT

OCTOBER 2000
P700-00-009

Gray Davis, *Governor*

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Preface

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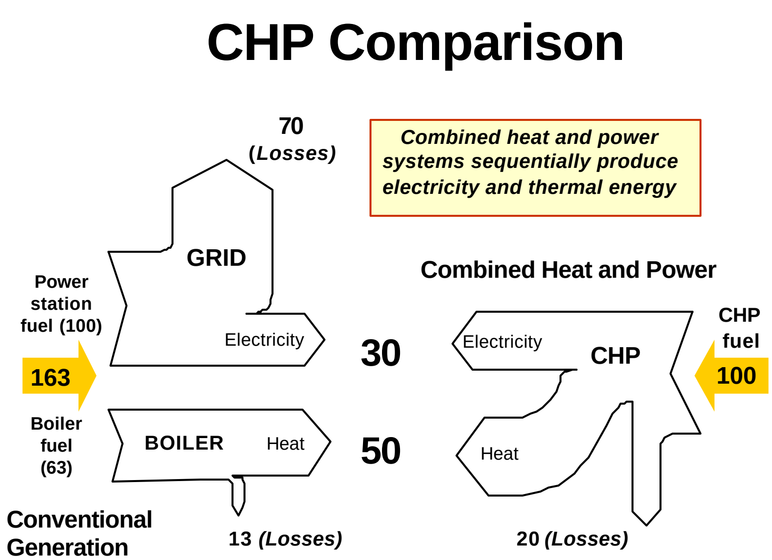
Executive Summary

Overview

This report provides an assessment of combined heat and power (CHP) systems in the state of California. The detailed report describes the technologies, applications, existing utilization and benefits of CHP. These data and the emerging economics of restructured energy markets are then used as the basis for developing an evaluation of the technical market potential for CHP in California and scenarios for future market penetration.

For the average power plant, over two-thirds of the energy content of the input fuel is wasted in the form of heat. As an alternative, an end-user can generate both its thermal and electrical energy needs in a single combined heat and power (CHP) system located at or near the facility. CHP, also called cogeneration, can significantly increase the efficiency of energy utilization, reduce emissions of criteria pollutants and CO_2, and lower operating costs for industrial, commercial and institutional users. Figure ES1 compares a CHP system providing 80 units of useful thermal and electric energy in a single process with just 20 units of losses with separate production of heat and electricity that produces 83 units wasted energy.

Figure ES-1 CHP versus Separate Power Generation and Heat Production



In addition to more efficient use of energy, CHP offers additional benefits of lower costs to meet energy needs, lower overall emissions, and ancillary benefits to both customers and utilities.

- California companies currently have average commercial and industrial electricity rates that are higher than 80 to 90% of all customers in the U.S. -- $0.097/kWh for commercial users and \$0.063/kWh for industrials. The net cost of power production from a CHP system can be considerably below these retail rates, providing an economic surplus that will enhance productivity and economic growth in the state.

- CHP technologies can significantly reduce emissions of both pollutants such as NOx and SO2 and gases that contribute to global warming such as CO2.

- CHP offers a customer enhanced reliability, operational and load management flexibility (when also connected to the grid), ability to arbitrage electric and gas prices, and energy management, including peak shaving and possibilities for enhanced thermal energy storage.

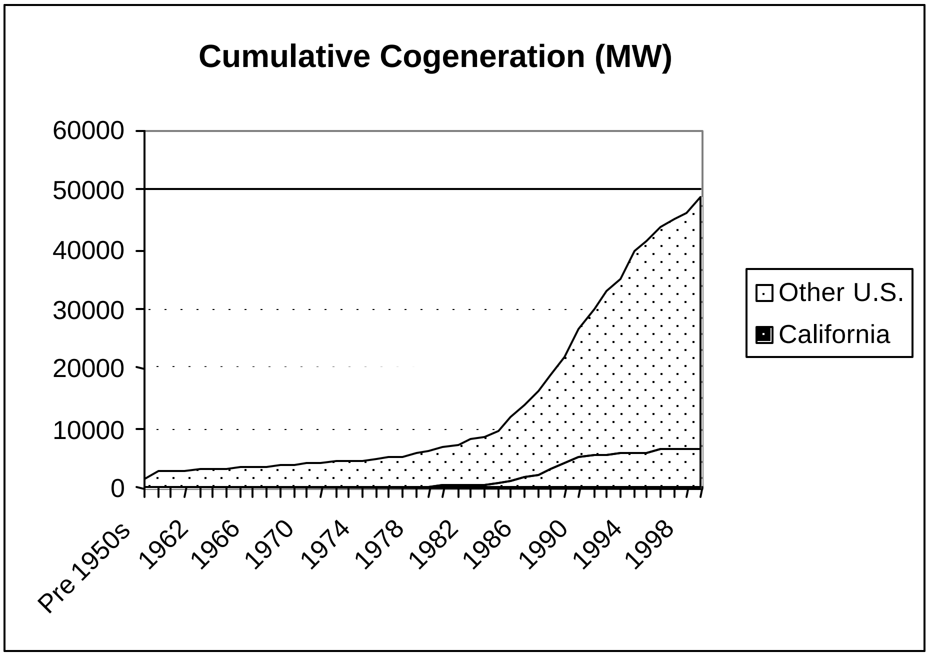
- In a restructured electric industry, CHP and other distributed generation options can offer grid support to the distribution utility. They also give energy service providers (ESPs) or users the ability to offer ancillary services to the system, including:
    * Voltage and frequency support to enhance reliability and power quality;
    * Avoidance or deferral of high cost, long lead time T&D upgrades;
    * Bulk power risk management;
    * Reduced line losses, reactive power control;
    * Outage cost savings;
    * Reduced central station generating reserve requirements;
    * Transmission capacity release.

From the early days of electricity production, certain energy intensive industries such as pulp and paper mills, chemical plants and oil refineries generated their own steam and power onsite with large CHP systems. CHP was generally confined to these large-scale industrial processes until the Public Utilities Regulatory policy Act of 1978 (PURPA). PURPA made it mandatory for electric utilities to interconnect with all qualifying CHP and small renewable power facilities, to purchase power from these facilities at their avoided costs, and to provide supplementary and backup power on a nondiscriminatory basis. During the decade immediately following the passage of PURPA, CHP capacity in the U.S. began growing at an annual rate to 6.3%. During the nineties, average growth has remained over 5%, but that is mostly due to a large number of installations early in the decade. Growth has tailed off considerably in the last few years.

Growth of CHP in California was dramatically increased by PURPA. Before its passage, there were only 9 cogeneration units operating in the state. Over the next ten years, more than 380 additional cogeneration plants were built. The decade from 1988 to 1997 added over 270 more units. Annual growth in cogeneration capacity went from less than 1% in the seventies to 27% in the eighties. By the nineties, the rate had slowed to just over 4%. In 1998, after nearly sixteen years of double-digit plant additions, only one cogeneration plant was added. The cumulative market growth for CHP in the U.S. and in California are shown in **Figure ES2**.

Currently, there are close to 50,000 MW of CHP capacity nationwide and nearly 6,500 MW in California.

Figure ES-2. Operating CHP by Year of Initial Operation



The observed CHP market decline in California can be attributed to a variety of factors, most notably a structural conflict of interests between the CHP developers and customers on one side and the regulated utility industry on the other side. Cost-of-service regulation of electric utilities that based their profit on the size of their facilities investment made them both vulnerable to competition due to over-investment and at the same time resistant to any competitive power investments on the part of their customers. This utility resistance led to imposition of market barriers to CHP investment. Developers faced complicated and costly interconnect requirements, expensive rates for back-up power, and the steady lowering of the PURPA mandated avoided costs offered for CHP generated power. One of the biggest barriers to continued CHP market development was the discriminatory utility practice of offering special low rates to customers that begin to develop (or threaten to develop) CHP systems. At the same time, rigorous efforts to reduce air pollution led to policies that made it all but impossible to site new CHP systems even though such systems could arguably have a net reduction in the combined emissions of generating heat and power through separate processes.

The motivation for this current study of CHP opportunities in California is to reevaluate the economics, benefits, and market potential in the restructured competitive market for power.

ES-1 Combined Heat and Power Technologies

CHP systems are complex integrated systems that consist of a number of individual components from fuel treatment, combustion, mechanical energy, electric energy, electricity conditioning, heat recovery, and heat rejection systems. However, they are typically identified by the prime-mover that drives the overall system. Several different technologies are used for CHP.

Reciprocating engines are among the most widely used and most efficient prime movers used in CHP systems. Electric efficiencies of 25%-50% make reciprocating engines an economic CHP option in many applications. The two most common types of reciprocating engines spark-ignited engines usually fired with natural gas (Otto cycle) and compression-ignited (diesel cycle) engines fired with diesel fuel, heavy oil, or a combination of oil and gas. These engines can range in size from a few kilowatts to very large engines with capacities of several megawatts.

Steam turbines are one of the most versatile and oldest prime mover technologies used to drive a generator or mechanical machinery. Steam turbines are widely used for CHP applications in the U.S. and Europe where special designs have been developed to maximize efficient steam utilization. A steam turbine is captive to a separate heat source and does not directly convert a fuel source to electric energy. Steam turbines require a source of high pressure steam that is produced in a boiler or heat recovery steam generator (HRSG). Boiler fuels can include fossil fuels such as coal, oil and natural gas or renewable fuels like wood or municipal waste.

Combustion turbines (CT) use the expansion of hot combustion gases rather than steam to drive the rotating power turbine section. CTs drive an integral front end intake air compressor and fuel combustion section that heats the compressed air to high temperatures to drive the power turbine. CTs are derived from jet engines used in planes. Continuous technical innovation has made them a very compact and efficient prime mover for power generation. The most common fuel source for power generation in this country is natural gas, though a broad range of gaseous and liquid fuels can also be burned. CTs represented only 20% of the power generation market twenty years ago; they now claim approximately 40% of new capacity additions. CTs are economic for CHP in sizes from 5 MW to several hundred MW.

Combined cycle plants are combustion turbines that use the heat energy contained in the exhaust to produce steam that in turn is used to drive a separate steam turbine. Combined cycle plants usually are over 100 MW but systems as small as 8 MW are available commercially. Combined cycle systems have electrical generation efficiencies approaching 60% in the largest systems

Microturbines are exactly, as their name implies, very small combustion turbines sized from 30 to 250 kW. Microturbines more closely resemble automobile and truck turbochargers than the much larger, complex, multistage CTs. Most, though not all, microturbines operate at very high speed (70,000 to 100,000 rpm) that drive a high speed generator directly. This high frequency power must then be rectified and inverted to 60 Hz using complex power electronics gear.

Several companies are developing microturbine systems that will be commercialized in the next few years.

Fuel cells are a class of technologies that convert a chemical fuel directly into electricity in a manner analogous to a chemical storage battery except the chemical input is not stored as in a battery but fed continuously into the cell. The chemical input to the cell is in the form of hydrogen and oxygen. Several types of fuels can be used as the hydrogen source for these systems through a process called reforming. Fuel cells are an emerging technology. There has been a limited commercial introduction of fuel cells for CHP and several additional fuel cell technologies are in development. Fuel cells are inherently efficient and clean, but cost engineering is needed to bring current costs down to a competitive range.

Figure ES3 and ES4 show the breakdown of the 668 operating CHP systems in California by primary technology. CHP systems generally consist of a heat engine (prime-mover) driving an electric generator that usually though not always connected with the electric distribution system and a means of heat recovery that is tied into a customer's thermal processes.

Figure ES-3. Existing CHP, Number of Sites by Technology

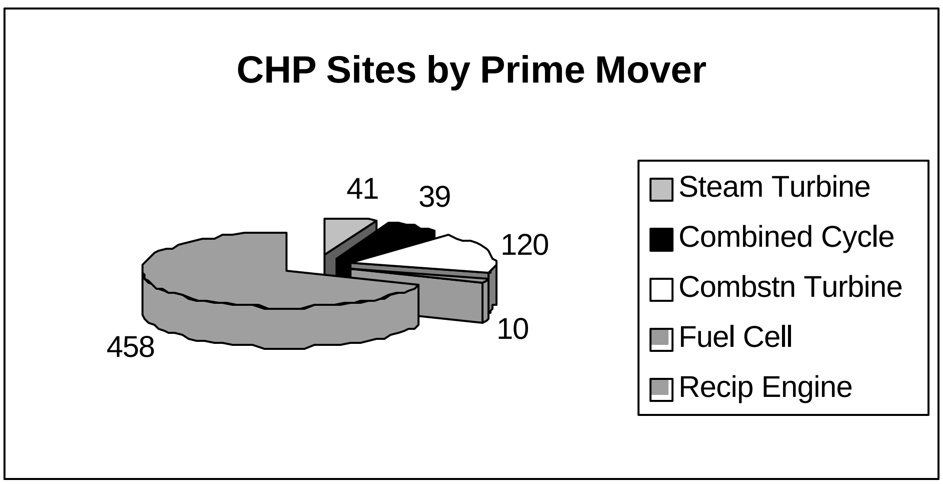


Figure ES-4. Existing CHP, MW Capacity by Technology

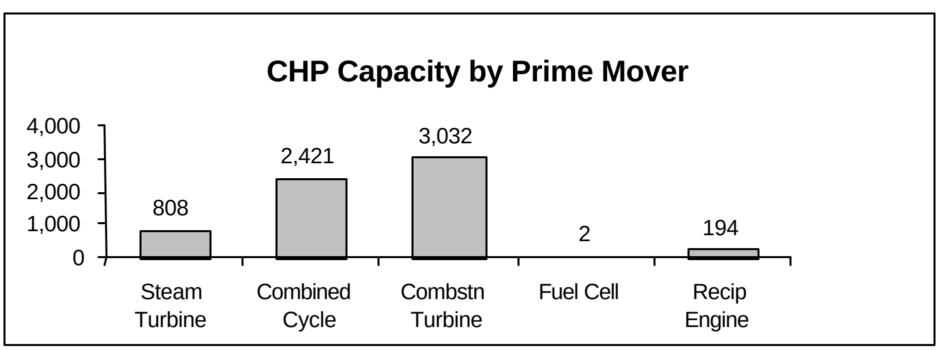


Table ES-1 summarizes selected design and performance features for these CHP technologies.

Table ES-1. Comparison of CHP Technologies

	Diesel Engine	Natural Gas Engine	Steam Turbine	Gas Turbine	Micro-turbine	Fuel Cells
Electric Efficiency (LHV)	30-50%	25-45%	30-42%	25-40% (simple)40-60% (combined)	20-30%	40-70%
Footprint (sqft/kW)	0.22	0.22-0.31	<0.1	0.02-0.61	0.15-1.5	0.6-4
CHP installed cost ($/kW)	800-1500	800-1500	800-1000	700-900	500-1300	>3000
O&M Cost ($/kWh)	0.005-0.008	0.007-0.015	0.004	0.002-0.008	0.002-0.01	0.003-0.015
Fuels	diesel and residual oil	natural gas, biogas, propane	all	natural gas, biogas, propane, distillate oil	natural gas, biogas, propane, distillate oil	hydrogen, natural gas, propane
NO_x Emissions (lb/MWh)	3-33	2.2-28	1.8	0.3-4	0.4-2.2	<0.02
CHP Output (Btu/kWh)	3,400	1,000-5,000	n/a	3,400-12,000	4,000-15,000	500-3,700
Useable Temp for CHP (F)	180-900	300-500	n/a	500-1,100	400-650	140-700

ES-2 Market Potential

CHP is best applied at facilities that have significant and concurrent electric and thermal demands. In the industrial sector, CHP thermal output has traditionally been in the form of steam used for process and for space heating. For commercial and institutional users, thermal output has traditionally been steam or hot water used for space heating and potable water heating. The methodology employed to develop estimates for the technical potential for CHP in California consisted of the following steps:

- Identify target applications (by SIC) that can support CHP based on their thermal and electric loads and profiles using a combination of proprietary and CEC databases
- Identify the number of establishments in California for each of these SICs
- Develop size profiles for the SICs of interest (i.e., number of establishments by employee size categories
- Estimate average electric and thermal loads for the SICs of interest in each size category

- Estimate CHP potential for each SIC and size category based on number of establishments in each category and applicable electric and thermal loads, and then subtract out existing CHP capacity

Table ES-2 summarizes the results of the application matching for both the industrial and the commercial and institutional sectors by size category. A total of 12,108 MW of remaining CHP potential was identified for California roughly evenly split between the industrial and commercial sectors.

Table ES-2. Remaining Potential for CHP in the Commercial and Industrial Sectors

Summary of Remaining CHP Potential						
	Commercial		Industrial		Total	
	Sites	MW	Sites	MW	Sites	MW
50-250 kW	23,559	2,105	n.a.	n.a.	23,559	2,105
250-1,000 kW	2,638	1,438	1,280	648	3,918	2,086
1-5 MW	534	993	582	1,184	1,116	2,177
5-20 MW	69	446	104	1,055	173	1,501
> 20 MW	15	619	51	3,620	66	4,240
Total	26,815	5,602	2,017	6,506	28,832	12,108

In the industrial sector, the applications are concentrated in the petroleum, food processing, pulp and paper, and wood processing industries. In the commercial sector, the applications are concentrated in education, restaurants, hotels and lodging, and apartment buildings.

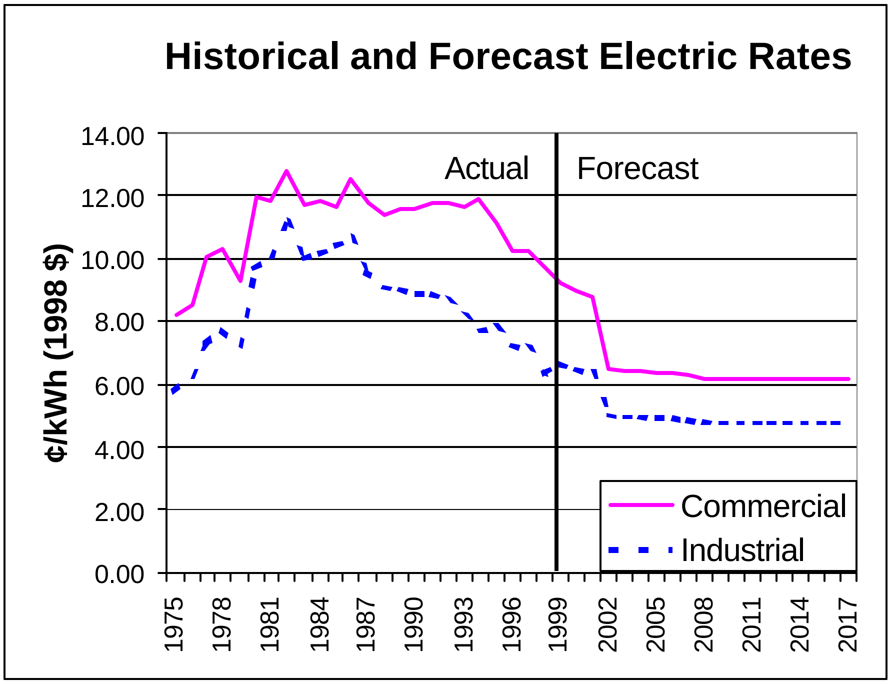
ES-3 Market Assessment

This section provides an assessment of potential CHP market penetration scenarios for California. The market penetration estimates are based on the technology cost and performance parameters, the total market potential for CHP, the economic competitiveness of CHP in different size and load applications, the historical market penetration for CHP by size and application, and an evaluation of the impacts of emerging technology and market trends.

Electricity Price Trends

The most significant variable determining future CHP market penetration rates is the expected future retail electricity price. The CEC electricity price forecast is shown in **Figure ES-5** along with the historical data in inflation adjusted real dollars. Electricity rates have been declining in real terms for both commercial and industrial customers since the early 1980's. A sharp drop in rates is forecast when the Competitive Transition Charge (CTC) for generation assets expires at the end of 2001 or shortly thereafter. This drop is then followed by a forecast of very stable but slightly declining real rates through the end of the forecast period in 2017. The CEC forecast shows the average real commercial rate after restructuring at $0.0615/kWh and the average industrial rate at $0.0477 /kWh, significantly lower than the commercial and industrial rates in 1997 ($0.1021 and $0.0711 ¢/kWh.) The prevailing rates against which CHP must compete over the forecast period will be much lower than they are now and less than half what they were during the peak years of CHP market expansion.

Figure ES-5. Historical and Forecast Commercial and Industrial Electric Prices in California (real ¢/kWh)

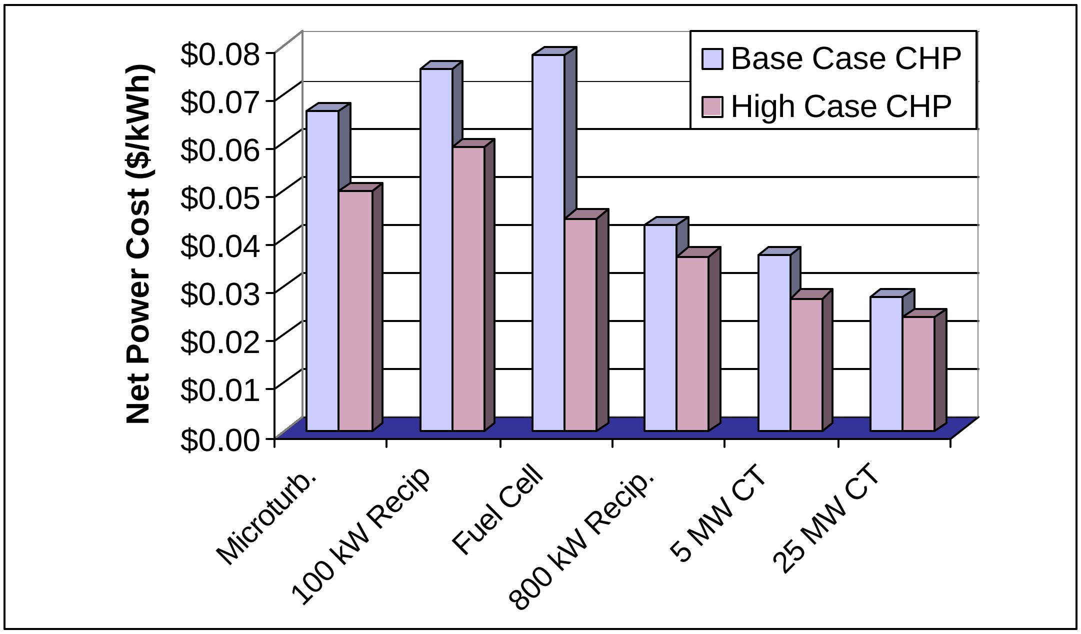


Market Penetration Cases

We selected a number of technology and application profiles that match the various size categories of technical CHP market potential from small microturbine and packaged engine systems to large gas turbines. The systems were all designed to operate base-load with the utility providing supplementary and backup power. Utilization of the thermal energy ranged from 60% in the smaller commercial applications to 90% for the largest industrial sites.

A **base case** was developed using commercial product specifications and a continuation of observed historical CHP penetration rates as a function of competing fuel and electric prices. A **high penetration case** was also developed based on near-term technology improvements, streamlined project implementation, CHP encouraging initiatives, and a higher marketing effort by energy service providers. **Figure ES-6** compares the net cost of electricity from typical CHP systems for both cases. The small engine and microturbine technologies are assumed to have an economic life of 10 years; all the rest are assumed to have an economic life of 15 years. The heat recovered replaces that produced by an 80% efficient gas-fired boiler. The gas cost for the analysis was assumed to be $2.50/mmBtu, representative of the average California Utility Electric Generation rate.

Figure ES6. Example Net Power Cost Levels for CHP Technologies for the Base and High Cases



In the base case forecast, the future CHP penetration is expected to continue at a declining level over time based on the average penetration rates experienced during the 1991-1996 period after the end of the initial market boom period for a total incremental penetration of CHP of 4000 MW. Over 90% of this penetration will be in the largest industrial size category of 20 MW and above resulting in a market saturation of 59% of the remaining potential in this size range.

In the base forecast, penetration of smaller packaged cogeneration systems less than one megawatt will continue to be an extremely small percentage of total unrealized potential—less than 1% of total potential sites. It should be emphasized that the base-case forecast depends on the penetration of CHP at historical and forecast energy prices and does not take into account the aggressive market plans of energy service providers that plan to offer packaged microturbines or fuel cells at an attractive price to small customers. The economics of the largest CHP systems will continue to be attractive. Penetration rates within this sector are forecast to equal two-thirds of the available, unrealized potential.

In the high penetration case, improvement to CHP package cost and performance, all else being equal, would raise cumulative CHP penetration over the forecast period from 4000 to 4575 MW—an increase of 14%. Adding the impacts of the various CHP initiatives to the improved technology would increase cumulative market penetration to 6143 MW—a total improvement compared to the base case of 53%. Finally, adding in the impacts of increased marketing effort and higher customer response rates provides for a cumulative CHP market penetration of 8,889 MW—a 222% increase compared to the base case. In the high case scenario, market saturation for CHP systems <1-MW in size would increase from less than 1% to more than 30%. This increase represents almost 5000 small systems with a combined capacity of 959 MW. Improvements in the middle range systems of 1-20 MW is also substantial, growing from 277 MW of cumulative penetration in the Base Case to 2113 MW in the High Case.

Table ES-3 shows the cumulative penetration in both capacity added and number of projects and the cumulative penetration of the remaining potential. The cumulative penetration is calculated on the basis of capacity in megawatts, and the current potential calculated in the previous section of the report is assumed to increase during the forecast period at 2% per year.

Table ES-3. High Case Cumulative Additions in Capacity and Projects and Percent Saturation of Total Remaining Available Market

CHP Category by Size	Cumulative Penetration in MW	Cumulative Penetration in Units	% of Total Market Penetrated
Base Case			
50-250 kW	0.8	8	0.03%
250-1000 kW	7.7	14	0.25%
1-5 MW	32.7	14	1.01%
5-20 MW	243.5	27	10.92%
> 20 MW	3724.7	45	59.12%
Total	4009.4	108	22.28%
High Market Scenario			
50-250 kW	389.9	3904	12.46%
250-1000 kW	568.9	1031	18.36%
1-5 MW	793.7	331	24.54%
5-20 MW	1319.7	148	59.18%
> 20 MW	5816.5	75	92.33%
Total	8888.7	5490	49.40%

The base case estimate for CHP penetration will provide the following benefits to California:

- 30 billion kWh of additional CHP production in the base case
- $1.6 billion in gross user benefits
- Reduced CO2 emissions of 11 million tons/year.
- Reduced customer outage costs of $168 million/year

The high case benefits are 2.2 times larger than the base case benefits due to the higher penetration levels.

1.0 Combined Heat and Power Technologies

Introduction

Combined heat and power (CHP) technologies produce electricity or mechanical power and recover waste heat for process use. Conventional centralized power systems average less than 33% delivered efficiency for electricity in the U.S.; CHP systems can deliver energy with efficiencies exceeding 90%[1], while significantly reducing emissions per delivered MWh. CHP systems can provide cost savings for industrial and commercial users and substantial emissions reductions for the State of California. Section 1 of this report describes the leading CHP technologies, their efficiency, size, cost to install and maintain, fuels and emission characteristics.

The technologies included in this report include diesel engines, natural gas engines, steam turbines, gas turbines, micro-turbines and fuel cells. Most CHP technologies are commercially available for on-site generation and combined heat and power applications. Several barriers (see Section 2, Market Potential), including utility interconnection costs and issues, environmental regulations and technology costs have kept these technologies from gaining wider acceptance. Many of the technologies are undergoing incremental improvements to decrease costs and emissions while increasing efficiency. The business environment is witnessing dramatic changes with utility restructuring and increased customer choice. As a result of these changes, CHP is gaining wider acceptance in the market (see Section 3).

Selecting a CHP technology for a specific application depends on many factors, including the amount of power needed, the duty cycle, space constraints, thermal needs, emission regulations, fuel availability, utility prices and interconnection issues. Table 1 summarizes the characteristics of each CHP technology. The table shows that CHP covers a wide capacity range from 25 kW micro-turbines to 250 MW gas turbines. Estimated costs per installed kW range from \$500-\$1000/kW for all the technologies except fuel cells.

[1] T. Casten, *CHP – Policy Implications for Climate Change and Electric Deregulation*, May 1998, p2.

Table 1-1. Comparison of CHP Technologies

	Diesel Engine	Natural Gas Engine	Steam Turbine	Gas Turbine	Micro-turbine	Fuel Cells
Electric Efficiency (LHV)	30-50%	25-45%	30-42%	25-40% (simple)40-60% (combined)	20-30%	40-70%
Size (MW)	0.05-5	0.05-5	Any	3-200	0.025-0.25	0.2-2
Footprint (sqft/kW)	0.22	0.22-0.31	<0.1	0.02-0.61	0.15-1.5	0.6-4
CHP installed cost ($/kW)	800-1500	800-1500	800-1000	700-900	500-1300	>3000
O&M Cost ($/kWh)	0.005-0.008	0.007-0.015	0.004	0.002-0.008	0.002-0.01	0.003-0.015
Availability	90-95%	92-97%	Near 100%	90-98%	90-98%	>95%
Hours between overhauls	25,000-30,000	24,000-60,000	>50,000	30,000-50,000	5,000-40,000	10,000-40,000
Start-up Time	10 sec	10 sec	1 hr-1 day	10 min –1 hr	60 sec	3 hrs-2 days
Fuel pressure (psi)	<5	1-45	n/a	120-500 (may require compressor)	40-100 (may require compressor)	0.5-45
Fuels	diesel and residual oil	natural gas, biogas, propane	all	natural gas, biogas, propane, distillate oil	natural gas, biogas, propane, distillate oil	hydrogen, natural gas, propane
Noise	moderate to high (requires building enclosure)	moderate to high (requires building enclosure)	moderate to high (requires building enclosure)	moderate (enclosure supplied with unit)	moderate (enclosure supplied with unit)	low (no enclosure required)
NO_x Emissions(lb/MWh)	3-33	2.2-28	1.8	0.3-4	0.4-2.2	<0.02
Uses for Heat Recovery	hot water, LP steam, district heating	hot water, LP steam, district heating	LP-HP steam, district heating	direct heat, hot water, LP-HP steam, district heating	direct heat, hot water, LP steam	hot water, LP-HP steam
CHP Output (Btu/kWh)	3,400	1,000-5,000	n/a	3,400-12,000	4,000-15,000	500-3,700
Useable Temp for CHP (F)	180-900	300-500	n/a	500-1,100	400-650	140-700

1.1 Reciprocating Engines

Introduction

Among the most widely used and most efficient prime movers are reciprocating (or internal combustion) engines. Electric efficiencies of 25-50% make reciprocating engines an economic CHP option in many applications. Several types of reciprocating engines are commercially available, however, two designs are of most significance to stationary power applications and include four cycle- spark-ignited (Otto cycle) and compression-ignited (diesel cycle) engines. They can range in size from small fractional portable gasoline engines to large 50,000 HP diesels for ship propulsion. In addition to CHP applications, diesel engines are widely used to provide standby or emergency power to hospitals, and commercial and industrial facilities for critical power requirements.

Technology Description

The essential mechanical parts of Otto-cycle and diesel engines are the same. Both use a cylindrical combustion chamber in which a close fitting piston travels the length of the cylinder. The piston is connected to a crankshaft which transforms the linear motion of the piston within the cylinder into the rotary motion of the crankshaft. Most engines have multiple cylinders that power a single crankshaft. Both Otto-cycle and diesel four stroke engines complete a power cycle in four strokes of the piston within the cylinder. Strokes include: 1) introduction of air (or air-fuel mixture) into the cylinder, 2) compression with combustion of fuel, 3) acceleration of the piston by the force of combustion (power stroke) and 4) expulsion of combustion products from the cylinder.

The primary difference between Otto and diesel cycles is the method of fuel combustion. An Otto cycle uses a spark plug to ignite a pre-mixed fuel-air mixture introduced to the cylinder. A diesel engine compresses the air introduced in the cylinder to a high pressure, raising its temperature to the ignition temperature of the fuel which is injected at high pressure.

A variation of the diesel is the dual fuel engine. Up to 80-90% of the diesel fuel is substituted with gasoline or natural gas while maintaining power output and achieving substantial emission reductions.

Large modern diesel engines can attain electric efficiencies near 50% and operate on a variety of fuels including diesel fuel, heavy fuel oil or crude oil. Diesel engines develop higher part load efficiencies than an Otto cycle because of leaner fuel-air ratios at reduced load.

Design Characteristics

The features that have made reciprocating engines a leading prime mover for CHP include:

Economical size range:	Reciprocating engines are available in sizes that match the electric demand of many end-users (institutional, commercial and industrial).
Fast start-up:	Fast start-up allows timely resumption of the system following a maintenance procedure. In peaking or emergency power applications, reciprocating engines can quickly supply electricity on demand.
Black-start capability:	In the event of a electric utility outage, reciprocating engines can be started with minimal auxiliary power requirements, generally only batteries are required.
Excellent availability:	Reciprocating engines have typically demonstrated availability in excess of 95%.
Good part load operation:	In electric load following applications, the high part load efficiency of reciprocating engines maintain economical operation.
Reliable and long life:	Reciprocating engines, particularly diesel and industrial block engines have provided many years of satisfactory service given proper maintenance.

Performance Characteristics

Efficiency

Reciprocating engines have electric efficiencies of 25-50% (LHV) and are among the most efficient of any commercially available prime mover. The smaller stoichiometric engines that require 3-way catalyst after-treatment operate at the lower end of the efficiency scale while the larger diesel and lean burn natural gas engines operate at the higher end of the efficiency range.

Capital Cost

CHP projects using reciprocating engines are typically installed between $800-$1500/kW. The high end of this range is typical for small capacity projects that are sensitive to other costs associated with constructing a facility, such as fuel supply, engine enclosures, engineering costs, and permitting fees.

Availability

Reciprocating engines have proven performance and reliability. With proper maintenance and a good preventative maintenance program, availability is over 95%. Improper maintenance can have major impacts on availability and reliability.

Maintenance

Engine maintenance is comprised of routine inspections/adjustments and periodic replacement of engine oil, coolant and spark plugs every 500-2,000 hours. An oil analysis is an excellent method to determine the condition of engine wear. The time interval for overhauls is recommended by the manufacturer but is generally between 12,000-15,000 hours of operation for a top-end overhaul and 24,000-30,000 for a major overhaul. A top-end overhaul entails a cylinder head and turbo-charger rebuild. A major overhaul involves piston/ring replacement and crankshaft bearings and seals. Typical maintenance costs including an allowance for overhauls is 0.01 - 0.015$/kWhr.

Heat Recovery

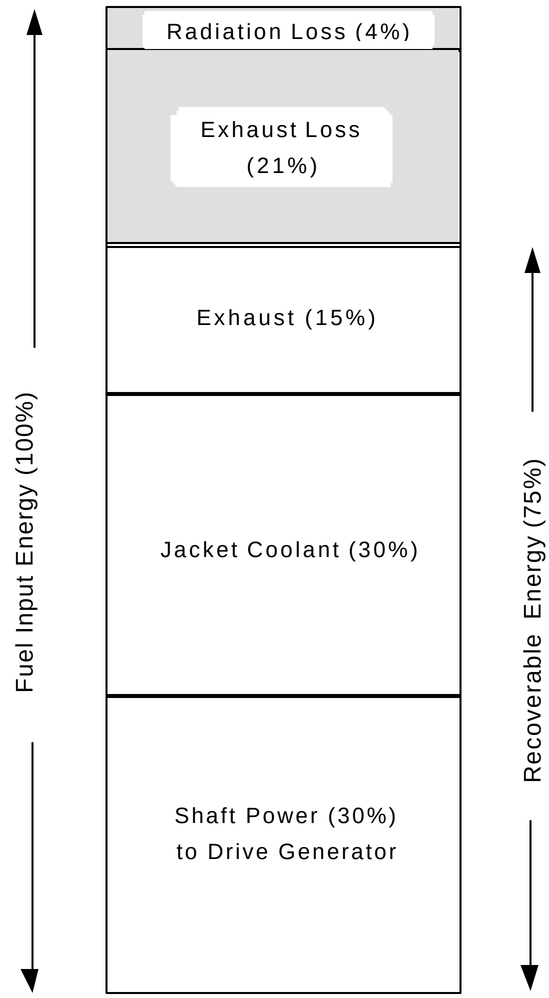
Energy in the fuel is released during combustion and is converted to shaft work and heat. Shaft work drives the generator while heat is liberated from the engine through coolant, exhaust gas and surface radiation. Approximately 60-70% of the total energy input is converted to heat that can be recovered from the engine exhaust and jacket coolant, while smaller amounts are also available from the lube oil cooler and the turbocharger's intercooler and aftercooler (if so equipped). Steam or hot water can be generated from recovered heat that is typically used for space heating, reheat, domestic hot water and absorption cooling.

Heat in the engine jacket coolant accounts for up to 30% of the energy input and is capable of producing 200°F hot water. Some engines, such as those with high pressure or ebullient cooling systems, can operate with water jacket temperatures up to 265°.

Engine exhaust heat is 10-30% of the fuel input energy. Exhaust temperatures of 850°-1200°F are typical. Only a portion of the exhaust heat can be recovered since exhaust gas temperatures are generally kept above condensation thresholds. Most heat recovery units are designed for a 300°-350°F exhaust outlet temperature to avoid the corrosive effects of condensation in the exhaust piping. Exhaust heat is typically used to generate hot water to about 230°F or low-pressure steam (15 psig).

By recovering heat in the jacket water and exhaust, approximately 70-80% of the fuel's energy can be effectively utilized as shown in Figure 1-1.1 for a typical spark-ignited engine.

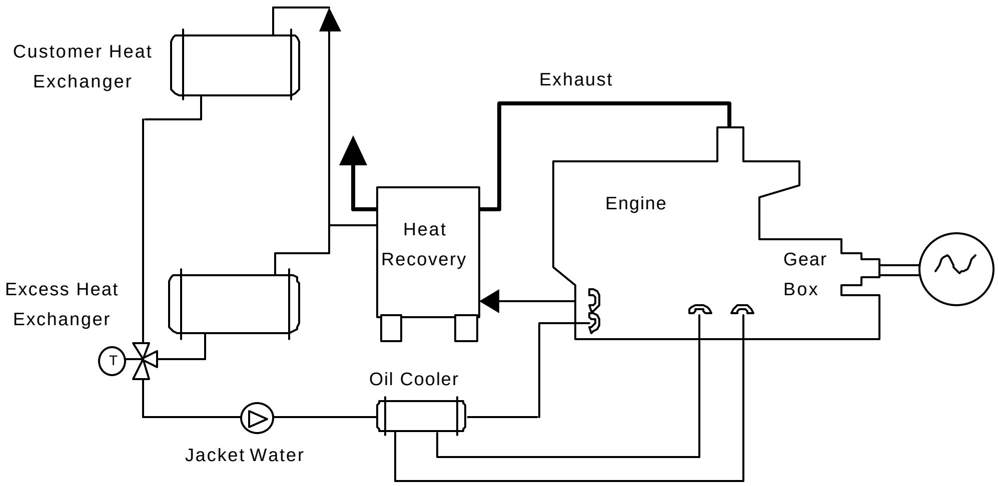
Figure 1-1.1 Energy Balance for a Reciprocating Engine



Closed-Loop Hot Water Cooling Systems

The most common method of recovering engine heat is the closed-loop cooling system as shown in Figure 1-1.2. These systems are designed to cool the engine by forced circulation of a coolant through engine passages and an external heat exchanger. An excess heat exchanger transfers engine heat to a cooling tower or radiator when there is excess heat generated. Closed-loop water cooling systems can operate at coolant temperatures between 190°-250°F.

Figure 1-1.2. Closed-Loop Heat Recovery System



Ebullient Cooling Systems

Ebullient cooling systems cool the engine by natural circulation of a boiling coolant through the engine. This type of cooling system is typically used in conjunction with exhaust heat recovery for production of low-pressure steam. Cooling water is introduced at the bottom of the engine where the transferred heat begins to boil the coolant generating two-phase flow. The formation of bubbles lowers the density of the coolant, causing a natural circulation to the top of the engine.

The coolant at the engine outlet is maintained at saturated steam conditions and is usually limited to 250°F and a maximum of 15 psig. Inlet cooling water is also near saturation conditions and is generally 2°- 3°F below the outlet temperature. The uniform temperature throughout the coolant circuit extends engine life, contributes to improved combustion efficiencies and reduces friction in the engine.

Emissions

The two primary methods of lowering emissions in Otto cycle engines is lean burn (combustion control) and rich burn with a catalytic after-treatment.

Lean burn engine technology was developed during the 1980's in response to the need for cleaner burning engines. Most lean burn engines use turbocharging to supply excess air to the engine and produce lean fuel-air ratios. Lean burn engines consume 50-100% excess air (above stoichiometric) to reduce temperatures in the combustion chamber and limit creation of nitrogen oxides (NO_x,) carbon dioxide (CO) and non-methane hydrocarbons (NMHC.) The typical NO_x emission rate for lean burn engines is between 0.5–2.0 grams/hphr. Emission levels can be reduced to less than 0.15gm/hphr with selective catalytic reduction (SCR) where ammonia is injected into the exhaust gas in the presence of a catalyst. SCR adds a significant cost burden to the installation cost and increases the O&M on the engine. This approach is typically used on large capacity engines.

Catalytic converters are used with rich burn (i.e. stoichiometric) Otto cycles. A reducing catalyst converts NO_x to N_2 and oxidizes some of the CO to CO_2. A catalytic converter can contain both reducing and oxidizing catalytic material in a single bed. Electronic fuel–air ratio controls are typically needed to hold individual emission rates to within a very close tolerance. Also referred to as a three-way catalyst, hydrocarbon, NO_x and CO are simultaneously controlled. Typical NO_x emission rates for rich burn engines are approximately 9 grams/hphr. Catalytic converters have proven to be the most effective after treatment of exhaust gas with control efficiencies of 90-99%+, reducing NO_x emissions to 0.15gm/hphr. A stoichiometric engine with a catalytic convertor operates with an efficiency of approximately 30%. Maintenance costs can increase by 25% for catalyst replacement.

Diesel engines operate at much higher air-fuel ratios than Otto cycle engines. The high excess air (lean condition) causes relatively low exhaust temperatures such that conventional catalytic converters for NO_x reduction are not effective. Lean NO_x catalytic converters are currently under development. Some diesel applications employ SCR to reduce emissions.

A major emission impact of a diesel engine is particulates. Particulate traps physically capture fine particulate matter generated by the combustion of diesel fuel and are typically 90% effective. Some filters are coated with a catalyst that must be regenerated for proper operation and long life. In some areas of California, such as areas under the jurisdiction of the South Coast Air Quality Management District (SCAQMD), diesel engines are very difficult to permit for continuous operation. Some exceptions apply for emergency generators.

Applications

Reciprocating engines are typically used in CHP applications where there is a substantial hot water or low pressure steam demand. When cooling is required, the thermal output of a reciprocating engine can be used in a single-effect absorption chiller. Reciprocating engines are available in a broad size range of approximately 50kW to 5,000kW suitable for a wide variety of commercial, institutional and small industrial facilities. Reciprocating engines are frequently used in load following applications where engine power output is regulated based on the electric demand of the facility. Thermal output varies accordingly. Thermal balance is achieved through supplemental heat sources such as boilers.

Technology Advancements

Advances in electronics, controls and remote monitoring capability should increase the reliability and availability of engines. Maintenance intervals are being extended through development of longer life spark plugs, improved air and fuel filters, synthetic lubricating oil and larger engine oil sumps.

Reciprocating engines have been commercially available for decades. A global network of manufacturers, dealers and distributors is well established.

1.2 Steam Turbines

Introduction

Steam turbines are one of the most versatile and oldest prime mover technologies used to drive a generator or mechanical machinery. Steam turbines are widely used for CHP applications in the U.S. and Europe where special designs have been developed to maximize efficient steam utilization.

Most of the electricity in the United States is generated by conventional steam turbine power plants. The capacity of steam turbines can range from a fractional horsepower to more than 1,300 MW for large utility power plants.

A steam turbine is captive to a separate heat source and does not directly convert a fuel source to electric energy. Steam turbines require a source of high pressure steam that is produced in a boiler or heat recovery steam generator (HRSG). Boiler fuels can include fossil fuels such as coal, oil and natural gas or renewable fuels like wood or municipal waste.

Steam turbines offer a wide array of designs and complexity to match the desired application and/or performance specifications. In utility applications, maximizing efficiency of the power plant is crucial for economic reasons. Steam turbines for utility service may have several pressure casings and elaborate design features. For industrial applications, steam turbines are generally of single casing design, single or multi-staged and less complicated for reliability and cost reasons. CHP can be adapted to both utility and industrial steam turbine designs.

Technology Description

The thermodynamic cycle for the steam turbine is the Rankine cycle. The cycle is the basis for conventional power generating stations and consists of a heat source (boiler) that converts water to high pressure steam. The steam flows through the turbine to produce power. The steam exiting the turbine is condensed and returned to the boiler to repeat the process.

A steam turbine consists of a stationary set of blades (called nozzles) and a moving set of adjacent blades (called buckets or rotor blades) installed within a casing. The two sets of blades work together such that the steam turns the shaft of the turbine and the connected load. A steam turbine converts pressure energy into velocity energy as it passes through the blades.

The primary type of turbine used for central power generation is the *condensing* turbine. Steam exhausts from the turbine at sub-atmospheric pressures, maximizing the heat extracted from the steam to produce useful work.

Steam turbines used for CHP can be classified into two main types:

The *non-condensing turbine* (also referred to as a back-pressure turbine) exhausts steam at a pressure suitable for a downstream process requirement. The term refers to turbines that exhaust steam at atmospheric pressures and above. The discharge pressure is established by the specific CHP application.

The *extraction turbine* has opening(s) in its casing for extraction of steam either for process or feedwater heating. The extraction pressure may or may not be automatically regulated depending on the turbine design. Regulated extraction permits more steam to flow through the turbine to generate additional electricity during periods of low thermal demand by the CHP system. In utility type steam turbines, there may be several extraction points each at a different pressure.

Design Characteristics

Custom design:	Steam turbines can be designed to match CHP design pressure and temperature requirements. The steam turbine can be designed to maximize electric efficiency while providing the desired thermal output.
High thermal quality:	Steam turbines are capable of operating over the broadest available steam pressure range from subatmospheric to supercritical and can be custom designed to deliver the thermal requirements of the CHP application.
Fuel flexibility:	Steam turbines offer the best fuel flexibility using a variety of fuel sources including nuclear, coal, oil, natural gas, wood and waste products.

Performance Characteristics

Efficiency

Modern large condensing steam turbine plants have efficiencies approaching 40-45%, however, efficiencies of smaller industrial or backpressure turbines can range from 15-35%.

Capital Cost
Boiler/ steam turbines installation costs are between $800-$1000/kW or greater depending on environmental requirements. The incremental cost of adding a steam turbine to an existing boiler system or to a combined cycle plant is approximately$400-$800/kW.

Availability
A steam turbine is generally considered to have 99%+ availability with longer than a year between shutdowns for maintenance and inspections. This high level of availability applies only for the steam turbine and does not include the heat source.

Maintenance
A maintenance issue with steam turbines is solids carry over from the boiler that deposit on turbine nozzles and degrades power output. The oil lubrication system must be clean and at the correct operating temperature and level to maintain proper performance. Other items include inspecting auxiliaries such as lubricating-oil pumps, coolers and oil strainers and check safety devices such as the operation of overspeed trips. Steam turbine maintenance costs are typically less than $0.004 per kWh.

Heat Recovery

Heat recovery methods from a steam turbine use exhaust or extraction steam. Heat recovery from a steam turbine is somewhat misleading since waste heat is generally associated with the heat source, in this case a boiler either with an economizer or air preheater.

A steam turbine can be defined as a heat recovery device. Producing electricity in a steam turbine from the exhaust heat of a gas turbine (combined cycle) is a form of heat recovery.

The amount and quality of the recovered heat is a function of the entering steam conditions and the design of the steam turbine. Exhaust steam from the turbine can be used directly in a process or for district heating. Or it can be converted to other forms of thermal energy including hot water or chilled water. Steam discharged or extracted from a steam turbine can be used in a single or double-effect absorption chiller. A steam turbine can also be used as a mechanical drive for a centrifugal chiller.

Emissions

Emissions associated with a steam turbine are dependent on the source of the steam. Steam turbines can be used with a boiler firing a large variety of fuel sources or it can be used with a gas turbine in a combined cycle. Boiler emissions can vary depending on environmental conditions. In the SCAQMD jurisdiction, large boilers use SCR to reduce NO_x emissions to single digit levels.

Applications

Steam Turbines for Industrial and CHP Applications

In industrial applications, steam turbines may drive an electric generator or equipment such as boiler feedwater pumps, process pumps, air compressors and refrigeration chillers. Turbines as industrial drivers are almost always a single casing machine, either single stage or multistage, condensing or non-condensing depending on steam conditions and the value of the steam. Steam turbines can operate at a single speed to drive an electric generator or operate over a speed range to drive a refrigeration compressor.

For non-condensing applications, steam is exhausted from the turbine at a pressure and temperature sufficient for the CHP heating application. Back pressure turbines can operate over a wide pressure range depending on the process requirements and exhaust steam at typically between 5 psig to 150 psig. Back pressure turbines are less efficient than condensing turbines, however, they are less expensive and do not require a surface condenser.

Combined Cycle Power Plants

The trend in power plant design is the combined cycle which incorporates a steam turbine in a bottoming cycle with a gas turbine. Steam generated in the heat recovery steam generator (HRSG) of the gas turbine is used to drive a steam turbine to yield additional electricity and improve cycle efficiency. The steam turbine is usually an extraction-condensing type and can be designed for CHP applications.

Technology Advancements

Steam turbines have been commercially available for decades. Advancements will more likely occur in gas turbine technology.

1.3 Gas Turbines

Introduction

Over the last two decades, the gas turbine has seen tremendous development and market expansion. Whereas gas turbines represented only 20% of the power generation market twenty years ago, they now claim approximately 40% of new capacity additions. Gas turbines have been long used by utilities for peaking capacity, however, with changes in the power industry and increased efficiency, the gas turbine is now being used for base load power. Much of this growth can be accredited to large (>50 MW) combined cycle plants that exhibit low capital cost (less than $550/kW) and high thermal efficiency. Manufacturers are offering new and larger capacity machines that operate at higher efficiencies. Some forecasts predict that gas turbines may furnish more than 80% of all new U.S. generation capacity in coming decades.[2]

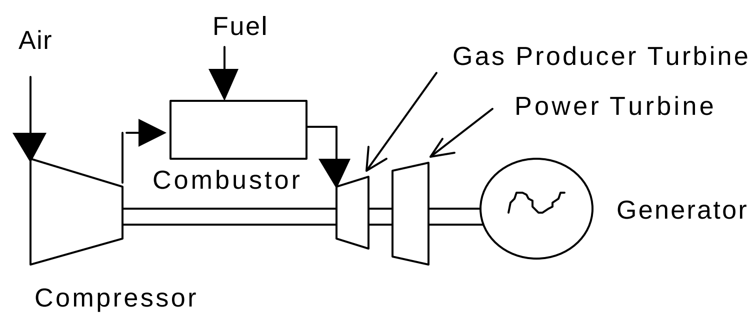
[2] U.S. DOE Energy Information Administration

Gas turbine development accelerated in the 1930's as a means of propulsion for jet aircraft. It was not until the early 1980's that the efficiency and reliability of gas turbines had progressed sufficiently to be widely adopted for stationary power applications. Gas turbines range in size from 30 kW (microturbines) to 250 MW (industrial frames).

Technology Description

The thermodynamic cycle associated with the majority of gas turbine systems is the Brayton cycle, that passes atmospheric air, the working fluid, through the turbine only once. The thermodynamic steps of the Brayton cycle include compression of atmospheric air, introduction and ignition of fuel, and expansion of the heated combustion gases through the gas producing and power turbines. The developed power is used to drive the compressor and the electric generator. Primary components of a gas turbine are shown in Figure 1-3.1.

Figure 1-3.1. Components of a Gas



Aeroderivative gas turbines for stationary power are adapted from their jet engine counterpart. These turbines are light weight and thermally efficient, however, are limited in capacity. The largest aeroderivitives are approximately 40 MW in capacity today. Many aeroderivative gas turbines for stationary use operate with compression ratios up to 30:1 requiring an external fuel gas compressor. With advanced system developments, aeroderivitives are approaching 45% simple cycle efficiencies.

Industrial or frame gas turbines are available between 1 MW to 250 MW. They are more rugged, can operate longer between overhauls, and are more suited for continuous base-load operation. However, they are less efficient and much heavier than the aeroderivative. Industrial gas turbines generally have more modest compression ratios up to 16:1 and often do not require an external compressor. Industrial gas turbines are approaching simple cycle efficiencies of approximately 40% and in combined cycles are approaching 60%.

Small industrial gas turbines are being successfully used in industry for onsite power generation and as mechanical drivers. Turbine sizes are typically between 1–10 MW for these applications. Small gas turbines drive compressors along natural gas pipelines for cross country transport. In the petroleum industry they drive gas compressors to maintain well pressures. In the steel industry they drive air compressors used for blast furnaces. With the coming competitive electricity market, many experts believe that installation of small industrial gas turbines will proliferate as a cost effective alternative to grid power.

Design Characteristics

Quality thermal output:	Gas turbines produce a high quality thermal output suitable for most CHP applications.
Cost effectiveness:	Gas turbines are among the lowest cost power generation technologies on a $/kW basis, especially in combined cycle.
Fuel flexibility:	Gas turbines operate on natural gas, synthetic gas and fuel oils. Plants are often designed to operate on gaseous fuel with a stored liquid fuel for backup.
Reliable and long life:	Modern gas turbines have proven to be reliable power generation devices, given proper maintenance.
Economical size range:	Gas turbines are available in sizes that match the electric demand of many end-users (institutional, commercial and industrial).

Performance Characteristics

Efficiency

The thermal efficiency of the Brayton cycle is a function of pressure ratio, ambient air temperature, turbine inlet temperature, the efficiency of the compressor and turbine elements and any performance enhancements (i.e. recuperation, reheat, or combined cycle). Efficiency generally increases for higher power outputs and aeroderivative designs. Simple cycle efficiencies can vary between 25-40% lower heating value (LHV). Next generation combined cycles are being advertised with electric efficiencies approaching 60%.

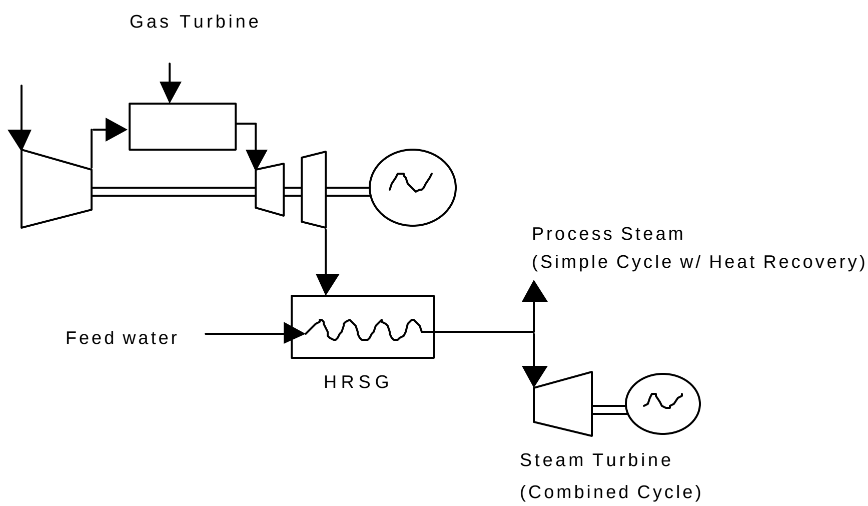
Capital Cost

The capital cost of a gas turbine power plant on a kW basis ($/kW) can vary significantly depending on the capacity of the facility. Typical estimates vary between $300-$900/kW. The lower end applies to large industrial frame turbines in combined cycle.

Availability
Estimated availability of gas turbines operating on clean gaseous fuels like natural gas is in excess of 95%. Use of distillate fuels and other fuels with contaminants require more frequent shutdowns for preventative maintenance that reduce availability.

Maintenance
Although gas turbines can be cycled, maintenance costs can triple for a turbine that is cycled every hour versus a turbine that is operated for intervals of 1000 hours. Operating the turbine over the rated design capacity for significant time periods will also dramatically increase the number of hot path inspections and overhauls. Maintenance costs of a turbine operating on fuel oil can be approximately three times that as compared to natural gas. Typical maintenance costs for a gas turbine fired by natural gas is 0.003-0.005 $/kWh.

Figure 1-3.2 Heat Recovery from a Gas Turbine System



Heat Recovery

The simple cycle gas turbine is the least efficient arrangement since there is no recovery of heat in the exhaust gas. Hot exhaust gas can be used directly in a process or by adding a heat recovery steam generator (HRSG), exhaust heat can generate steam or hot water.

For larger gas turbine installations, combined cycles become economical, achieving approximately 60% electric generation efficiencies using the most advanced utility-class gas turbines. The heat recovery options available from a steam turbine used in the combined cycle can be implemented to further improve the overall system efficiency (as discussed previously.)

Since gas turbine exhaust is oxygen rich, it can support additional combustion through supplementary firing. A duct burner is usually fitted within the HRSG to increase the exhaust gas temperature at efficiencies of 90% and greater.

Emissions

The dominant NO_x control technologies for gas turbines include water/steam injection and lean pre-mix (combustion control) and selective catalytic reduction (post combustion control). Without any controls, gas turbines produce levels of NO_x between 75-200 ppmv. By injecting water or steam into the combustor, NO_x emissions can be reduced to approximately 42 ppmv with water and 25 ppmv with steam. NO_x emissions from distillate-fired turbines can be reduced to about 42-75 ppmv. Water or steam injection requires very purified water to minimize the effects of water-induced corrosion of turbine components.

Lean pre-mix (dry low NO_x) is a combustion modification where a lean mixture of natural gas and air are pre-mixed prior to entering the combustion section of the gas turbine. Pre-mixing avoids "hot spots" in the combustor where NO_x forms. Turbine manufacturers have achieved NO_x emissions of 9-42 ppmv using this technology. This technology is still being developed and early designs have caused turbine damage due to "flashback". Elevated noise levels have also been encountered.

Selective catalytic reduction (SCR) is a post combustion treatment of the turbine's exhaust gas in which ammonia is reacted with NO_x in the presence of a catalyst to produce nitrogen and water. SCR is approximately 80-90% effective in the reduction of upstream NO_x emission levels. Assuming a turbine has NO_x emissions of 25 ppm, SCR can further reduce emissions to 3-5 ppm. SCR is used in series with water/steam injection or lean pre-mix to produce single-digit emission levels. SCR requires an upstream heat recovery device to temper the temperature of the exhaust gas in contact with the catalyst. SCR requires onsite storage of ammonia, a hazardous chemical. In addition ammonia can "slip" through the process unreacted that contributes to air pollution. SCR systems are expensive and significantly impact the economic feasibility of smaller gas turbine projects.

Applications

Gas turbines are a cost effective CHP alternative for commercial and industrial end-users with a base load electric demand greater than about 5 MW. Although gas turbines can operate satisfactorily at part load, they perform best at full power in base load operation. Gas turbines are frequently used in district steam heating systems since their high quality thermal output can be used for most medium pressure steam systems.

Gas turbines for CHP can be in either a simple cycle or a combined cycle configuration. Simple cycle applications are most prevalent in smaller installations typically less than 25 MW. Waste heat is recovered in a HRSG to generate high or low pressure steam or hot water. The thermal product can be used directly or converted to chilled water with single or double effect absorption chillers.

Technology Advancements

Advancements in blade design, cooling techniques and combustion modifications including lean premix (dry low NOx) and catalytic combustion are under development to achieve higher thermal efficiencies and single digit emission levels without post combustion treatment. Gas turbine manufacturers have been commercializing their products for decades. A global network of manufacturers, dealers and distributors is well established.

1.4 Microturbines

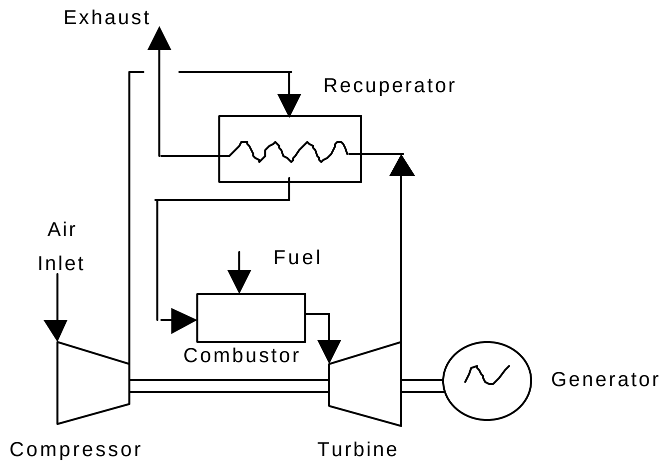
Introduction

A new class of small gas turbines called microturbines is emerging for the distributed resource market. Several manufacturers are developing competing engines in the 25-250 kW range, however, multiple units can be integrated to produce higher electrical output while providing additional reliability. Most manufacturers are pursuing a single shaft design wherein the compressor, turbine and permanent-magnet generator are mounted on a single shaft supported on lubrication-free air bearings. These turbines operate at speeds of up to 120,000 rpm and are powered by natural gas, gasoline, diesel, and alcohol. The dual shaft design incorporates a power turbine and gear for mechanical drive applications and operate up to speeds of 40,000 rpm. Microturbines are a relatively new entry in the CHP industry and therefore many of the performance characteristics are estimates based on demonstration projects and laboratory testing.

Technology Description

The operating theory of the microturbine is similar to the gas turbine, except that most designs incorporate a recuperator to recover part of the exhaust heat for preheating the combustion air. Air is drawn through a compressor section, mixed with fuel and ignited to power the turbine section and the generator. The high frequency power that is generated is converted to grid compatible 60HZ through power conditioning electronics. For single shaft machines, a standard induction or synchronous generator can be used without any power conditioning electronics.

Figure 1-4.1. Schematic of a Recuperated Microturbine



Design Characteristics

Compact:	Their compact and lightweight design makes microturbines an attractive option for many light commercial/ industrial applications.
Right-sized:	Microturbine capacity is right sized for many customers with relatively high electric costs.
Lower noise:	Microturbines promise lower noise levels and can be located adjacent to occupied areas.

Performance Characteristics

Efficiency
Most designs offer a recuperator to maintain high efficiency while operating at combustion temperatures below NO_x formation levels. With recuperation, efficiency is currently in the 20%-30% LHV range.

Capital Cost
Installed prices of $500-1000/kW for CHP applications is estimated when microturbines are mass produced.

Availability
Although field experience is limited, manufacturers claim that availability will be similar to other competing distributed resource technologies, i.e. in the 90->95% range.

Maintenance

Microturbines have substantially fewer moving parts than engines. The single shaft design with air bearings will not require lubricating oil or water, so maintenance costs should be below conventional gas turbines. Microturbines that use lubricating oil should not require frequent oil changes since the oil is isolated from combustion products. Only an annual scheduled maintenance interval is planned for micoturbines. Maintenance costs are being estimated at 0.006-0.01$/kW.

Heat Recovery

Hot exhaust gas from the turbine section is available for CHP applications. As discussed previously, most designs incorporate a recuperator that limits the amount of heat available for CHP. Recovered heat can be used for hot water heating or low pressure steam applications.

Emissions

NO_x emissions are targeted below 9 ppm using lean pre-mix technology without any post combustion treatment.

Applications

Markets for the microturbine include commercial and light industrial facilities. Since these customers often pay more for electricity than larger end-users, microturbines may offer these customers a cost effective alternative to the grid. Their relatively modest heat output may be ideally matched to customers with low pressure steam or hot water requirements. Manufacturers will target several electric generation applications, including standby power, peak shaving and base loaded operation with and without heat recovery.

One manufacturer is offering a two shaft turbine that can drive refrigeration chillers (100-350 tons), air compressors and other prime movers. The system also includes an optional heat recovery package for hot water and steam applications.

Technology Advancements

Microturbines are being developed in the near term to achieve thermal efficiencies of 30% and NOx emissions less than 10 ppm. It is expected that performance and maintenance requirements will vary among the initial offerings. Longer term goals are to achieve thermal efficiencies between 35-50% and NOx emissions between 2-3 ppm through the use of ceramic components, improved aerodynamic and recuperator designs and catalytic combustion.

Manufacturers are currently releasing prototype systems for demonstration and testing. Commercialization is planned by year 2000 with significant cost reductions expected as manufacturing volume increases.

1.5 Fuel Cells

Introduction

Fuel cells offer the potential for clean, quiet, and very efficient power generation, benefits that have driven their development in the past two decades. Fuel cells offer the ability to operate at electrical efficiencies of 40-60% (LHV) and up to 85% in CHP. Development of fuel cells for commercial use began in earnest in the 1970's for stationary power and transportation applications.

Although several fuel cell designs are under development, only the phosphoric acid fuel cell (PAFC) is commercially available. The price of the most competitive PAFC is still around $3000/kW which is still too high for most industrial and commercial applications. The fuel cell requires continued research and development before it becomes a serious contender in the CHP market.

Technology Description

Fuel cells are similar to batteries in that they both produce a direct current (DC) through an electrochemical process without direct combustion of a fuel source. However, whereas a battery delivers power from a finite amount of stored energy, fuel cells can operate indefinitely provided that a fuel source is continuously supplied. Two electrodes (a cathode and anode) pass charged ions in an electrolyte to generate electricity and heat. A catalyst is used to enhance the process. Individual fuel cells produce between 0.5-0.9 volts of DC electricity. Fuel cells are combined into "stacks" like a battery to obtain usable voltage and power output.

A fuel cell consists of several major components including a fuel reformer to generate hydrogen-rich gas, a power section where the electrochemical process occurs and a power conditioner to convert the direct current (DC) generated in the fuel cell into alternating current (AC). Fuel reforming "frees" the hydrogen in the fuel and removes other contaminants that would otherwise poison the catalytic electrodes. Fuel processing is usually performed at the point of use eliminating storage of the hydrogen-rich mixture. Depending on the operating temperature of the fuel cell, fuel reforming can occur external or internal the cell.

The general design of most fuel cells is similar except for the type of electrolyte used. The five main types of fuel cells are defined by their electrolyte and include alkaline, proton exchange membrane (PEMFC), phosphoric acid (PAFC), molten carbonate (MCFC) and solid oxide (SOFC) fuel cells. A comparison of fuel cell types is presented in Table 1-5.1.

Alkaline fuel cells which are very efficient and have been used successfully in the space program, require very pure hydrogen that is expensive to produce and for this reason are not considered major contenders for the stationary power market.

The PAFC represents the most mature technology and is commercially available today, having been installed in over 80 locations in the U.S., Europe and Japan.

The MCFC which is currently being demonstrated at several sites operates at higher temperature and is more efficient than the commercially available PAFC with efficiencies up to 55% (LHV) estimated. The high exhaust temperature of a MCFC can generate additional electricity in a steam turbine or in a gas turbine combined cycle. The MCFC is expected to target 1-20 MW stationary power applications and should be well suited for industrial CHP.

Many experts believe that the SOFC will be the dominant technology for stationary power applications. The SOFC offers the reliability of all-solid ceramic construction and is expected to have an electric efficiency of up to 50% (LHV). The high exhaust temperature of a SOFC can generate additional electricity in a steam turbine or in a gas turbine combined cycle. Hybrid systems using gas turbines or microturbines could increase electric efficiencies to 60%.

The PEMFC is of particular interest to the automotive industry as a future power plant for electric vehicles. Much of the current development effort is to introduce a PEMFC for the stationary power market as an intermediate step towards small and cost effective units for automobiles and buses. The PEMFC has very high power densities and can start-up quickly and meet varying demand.

Table 1-5.1: Comparison of Fuel Cell Types

	Alkaline (AFC)	**Proton Exchange Membrane (PEM)**	**Phosphoric Acid (PAFC)**	**Molten Carbonate (MCFC)**	**Solid Oxide (SOFC)**
Electrolyte	Alkaline lye	Perfluorated sulphonated polymer	Stabilized phosphoric acid	Molten carbonate solution	Ceramic solid electrolyte
Typical Unit Sizes (kW)	<<100	0.1-500	5-200 (plants up to 5,000)	800-2000 (plants up to 100,000)	2.5-100,000
Electric Efficiency	Up to 70%	Up to 50%	40-45%	50-57%	45-50%
Installed Cost ($/kW)		4,000	3,000-3,500	800-2,000	1,300-2,000
Commercial Availability	Not for CHP	R&D	Yes	R&D	R&D
Power Density lbs/kW ft^3/kW		8-10 ~0.2	~25 0.4	~60 ~1	~40 ~1
Heat Rejection (Btu/kWh)		1640 @ 0.8 V	1880 @0.74V	850 @0.8V	1780 @0.6V
Electric/ Thermal Energy		~ 1	~ 1	Up to 1.5	Up to 1.5
Oxidation Media	Oxygen	Oxygen from Air	Oxygen from Air	Oxygen from Air	Oxygen from Air
Cooling Medium		Water	Boiling Water	Excess Air	Excess Air
Fuel	H_2	H_2 and reformed H_2	H_2 reformed from natural gas	H_2 and CO reformed from natural gas or coal gas	H_2 and CO reformed from natural gas or coal gas
Operating Temp (F)	160-210	120-210	320-410	1250	1500-1800
Operating Pressure (psig)		14.7-74	14.7-118	14.7-44	14.7->150
Applications	Space and military (today)	Stationary power (1997-2000) Bus, railroad, automotive propulsion (2000-2010)	Stationary power (1998) Railroad propulsion (1999)	Stationary power (2000->2005)	Stationary power and railroad propulsion (1998->2005)

Design Characteristics

Emissions:	Installation of PAFC has been exempted from air quality permits in some of the strictest districts in the country including South Coast Air Quality Management District in the Los Angeles basin.
Quiet operation:	Much of the appeal of the fuel cell is its quiet operation so that siting and special enclosures are of minimal concern.
Commercial use:	The 200kW PAFC is ideally suited to typical commercial installations.
Thermal quality:	The quality of the thermal product depends on the type of electrolyte. The commercially available PAFC operates at lower temperatures and therefore produces low pressure steam or hot water as a byproduct.

Performance Characteristics

Efficiency

The electric efficiency of fuel cells are dramatically higher than combustion-based power plants. The current efficiency of PAFC is 40% with a target of 40-60% (LHV) estimated. With the recovery of the thermal byproduct, overall fuel utilization could approach 85%. Fuel cells retain their efficiency at part load.

Capital Cost

The capital cost of fuel cells is currently much higher than competing distributed resources. The commercial PAFC currently costs approximately $3,000/kW. Fuel cell prices are expected to drop to $500-$1500/kW in the next decade with further advancements and increased manufacturing volumes. Substantial cost reductions in the stationary power market are expected from advancements in fuel cells used for transportation.

Availability

Theoretically, fuel cells should have higher availability and reliability than gas turbines or reciprocating engines since they have fewer moving parts. PAFC have run continuously for more than 5,500 hours which is comparable to other power plants. Limited test results for PAFC have demonstrated availability at 96% and 2500 hours between forced outages.

Maintenance

The electrodes within a fuel cell that comprise the "stack" degrade over time reducing the efficiency of the unit. Fuel cells are designed such that the "stack" can be removed. It is estimated that "stack" replacement is required between four and six years when the fuel cell is operated under continuous conditions. The maintenance cost for PAFC (200 kW) including an allowance for periodic stack replacements has been in the range of $0.02-$5 kWh. Improvements should bring the cost down to $0.015/kWhr over the twenty year life of the unit.

Heat Recovery

Significant heat is released in a fuel cell during electrical generation. The PAFC and PEMFC operate at lower temperatures and produce lower grades of waste heat generally suitable for commercial and industrial CHP applications. The MCFC and SOFC operate at much higher temperatures and produce heat that is sufficient to generate additional electricity with a steam turbine or a microturbine hybrid gas turbine combined cycle.

Emissions

Fuel cells have little environmental impact and have been exempted from air permitting requirements by several California Air Quality Management Districts.

Applications

The type of fuel cell determines the temperature of the heat liberated during the process and its suitability for CHP applications. Low temperature fuel cells generate a thermal product suitable for low pressure steam and hot water CHP applications. High temperature fuel cells produce high pressure steam that can be used in combined cycles and other CHP process applications. Although some fuel cells can operate at part load, other designs do not permit on/off cycling and can only operate under continuous base load conditions.

For stationary power, fuel cells are being developed for small commercial and residential markets and as peak shaving units for commercial and industrial customers.

In a unique innovation, high temperature fuel cells and gas turbines are being integrated to boost electric generating efficiencies. Combined cycle systems are being evaluated for sizes up to 25 MW with electric efficiencies of 60-70% (LHV). The hot exhaust from the fuel cell is combusted and used to drive the gas turbine. Energy recovered from the turbine's exhaust is used in a recuperator that preheats air from the turbine's compressor section. The heated air is then directed to the fuel cell and the gas turbine. Any remaining energy from the turbine exhaust can be recovered for CHP.

Technology Advancements

With the exception of PAFC, fuel cell technology is still being demonstrated in the field or in the laboratory. Significant development and funding will be required over the next 5-10 years to achieve projected performance and cost. Major activities include reformer design, size reduction and improved manufacturing techniques. Collaboration between industry and government has been a important factor in sustaining development efforts.

Development in the mobile market should have a major impact on fuel cell technology. It is anticipated that PEM technology will be demonstrated by the year 2000.

1.6 System Issues

Integrating a CHP technology with a specific application together as a system, requires an understanding of the engineering and site-specific criteria that will provide the most economic solution. The final design must address siting issues like noise abatement and footprint constraints. Engineering information for designing a technically and economically feasible system should include electric and thermal load profiles, capacity factor, fuel type, performance characteristics of the prime mover, etc. CHP by definition implies the simultaneous generation of two or more energy products that function as a system. This section of the report reviews some of the primary issues faced by the design engineer in selecting and designing a CHP system.

Environmental permitting and grid interconnection issues are not included here, but are discussed Section Two, Market Potential.

Electric and Thermal Load Profiles

One of the first and most important elements in the analysis of CHP feasibility is obtaining accurate representations of electric and thermal loads. This is particularly true for load following applications where the prime mover must adjust its electric output to match the demand of the end-user while maintaining zero output to the grid. A 30-minute or hourly load profile provides the best results for such an analysis. Thermal load profiles can consist of hot water use, low and high pressure steam consumption and cooling loads. The shape of the electric load profile and the spread between minimum and maximum values will largely dictate the number, size and type of prime mover. It is recommended that electric and thermal loads be monitored if such information is not available.

For base load CHP applications that export power to the grid and meet a minimum thermal load required under PURPA, sizing a CHP facility is largely dictated by capacity requirements in the wholesale energy market. Rather than meeting the demand of an end-user, such plants are dispatched to the grid along with other generating systems as a function of cost of generation.

Capacity factor is a key indicator of how the capacity of the prime mover is utilized during operation. Capacity factor is a useful means of indicating the overall economics of the CHP system. The capacity factor indicates the facility's proximity to baseload operation. Capacity factor is defined as follows:

$$Capacity\,Factor = \frac{Actual\ Energy\ Consumption}{Peak\ Capacity\ of\ Prime\ Mover\ x\ 8{,}760\ hours}$$

A low capacity factor is indicative of peaking applications that derive economic benefits generally through the avoidance of high demand charges. A high capacity factor is desirable for most CHP applications to obtain the greatest economic benefit. A high capacity factor effectively reduces the fixed unit costs of the system ($/kWh) and to remain competitive with grid supplied power.

Gas turbines are typically selected for applications with relatively constant electric load profiles to minimize cycling the turbine or operating the turbine for a large percentage of hours at part load conditions where efficiency declines rapidly. Gas turbines are ideal for industrial or institutional end-users with 24 hour operations or where export to the grid is intended.

Most commercial end-users have a varying electric load profile, i.e., high peak loads during the day and low loads after business hours at night. Natural gas reciprocating engines are a popular choice for commercial CHP due to good part-load operation, ability to obtain an air quality permit and availability of size ranges that match the load of many commercial and institutional end-users. Reciprocating engines exhibit high electric efficiencies meaning that there is less available rejected heat. This is often compatible with the thermal requirements of the end-user.

Micro-turbines are just emerging as a as a future distributed resource that will be ideally sized to meet the electric load profiles of many commercial and institutional end-users.
Exhaust heat can be recovered for hot water or steam loads.

Thermal demand of a commercial or institutional end-user often consists of hot water or low pressure steam demand in the winter and a cooling demand in the summer. Heat from the prime movers often used in a single-stage steam or hot water absorption chiller. This option allows the CHP system to operate continuously throughout the year while maintaining a good thermal load without the need to reject heat to the environment.

Quality of Recoverable Heat

The thermal requirements of the end-user may dictate the feasibility of a CHP system or the selection of the prime mover. Gas turbines offer the highest quality heat that is often used to generate power in a steam turbine. Gas turbines reject heat almost exclusively in its exhaust gas stream. The high temperature of this exhaust can be used to generate high pressure steam or lower temperature applications such as low pressure steam or hot water. Larger gas turbines (typically above 25 MW) are frequently used in combined cycles where high pressure steam is produced in the HRSG and is used in a steam turbine to generate additional electricity. The high levels of oxygen present in the exhaust stream allows for supplemental fuel addition to generate additional steam at high efficiency.

Some of the developing fuel cell technologies including molten carbonate fuel cells (MCFC) and solid oxide fuel cells (SOFC) will also provide high quality rejected heat comparable to a gas turbine.

Reciprocating engines and the commercially available phosphoric acid fuel cell (PAFC) produce a lower grade of rejected heat. Heating applications that require low pressure steam (15 psig) or hot water are most suitable, although the exhaust from a reciprocating engine can generate steam up to 100 psig.

Reciprocating engines typically have a higher efficiency than most gas turbines in the same output range and are a good fit where the thermal load is low relative to electric demand. Reciprocating engines can produce low and high pressure steam from its exhaust gas, although low pressure steam or hot water is generally specified. Jacket water temperatures are typically limited to 210F so that jacket heat is usually recovered in the form of hot water. All the jacket heat can be recovered if there is sufficient demand, however, only 40-60% of the exhaust heat can be recovered to prevent condensation of corrosive exhaust products in the stack that will limit equipment life.

Industrial Heat Recovery

Industrial sites that produce excess heat or steam from a process may offer a CHP opportunity. If the excess thermal energy is continuously available or at a high load factor and is of sufficient quality, this heat can be used in a "bottoming cycle" to generate electricity in a steam turbine. In addition to electrical generation, steam turbines are often used to drive rotating equipment like air compressors or refrigeration compressors. Through a variety of turbine designs, the steam exhausted from the turbine can be used for lower grade heating applications or cooling in a CHP configuration. Excess steam could also be used for reforming natural gas for a fuel cell.

Noise

Although fuel cells are relatively expensive to install, they are being tested in a number of sites typically where the cost of a power outage is significant to lost revenues or lost productivity and where uninterrupted power is mandatory. Their relatively quiet operation has appeal and these units are being installed in congested commercial areas. Locating a turbine or engine in a residential area usually requires special consideration and design modifications to be acceptable.

Engine and turbine installations are often installed in building enclosures to attenuate noise to surrounding communities. Special exhaust silencers or mufflers are typically required on exhaust stacks. Gas turbines require a high volume of combustion air, causing high velocities and associated noise. Inlet air filters can be fitted with silencers to substantially reduce noise levels.

Gas turbines are more easily confined within a factory supplied enclosure than reciprocating engines. Reciprocating engines require greater ventilation due to radiated heat that makes their installation in a sound-attenuating building often the most practical solution. Gas turbines require much less ventilation and can be concealed within a compact steel enclosure.

Foot Print

Phosphoric acid fuel cells and micro-turbines offer compact packaging and have an appeal to those end-users that are seeking a non-obtrusive power generation or CHP system. Larger gas turbines and reciprocating engines generally are isolated in either a factory enclosure or a separate building along with ancillary equipment.

Fuel Supply

A potential system issue for gas turbines is the supply pressure of the natural gas distribution system at the end-user's property line. Gas turbines need minimum gas pressures of about 120 psig for small turbines with substantially higher pressures for larger turbines. Assuming there is no high pressure gas service, the local gas distribution company would have to construct a high pressure gas line or the end-user must purchase a gas compressor. The economics of constructing a new line must consider the volume of gas sales over the life of the project.

Gas compressors may have reliability problems especially in the smaller size ranges. If "black start" capability is required, then a reciprocating engine may be needed to turn the gas compressor, adding cost and complexity.

Reciprocating engines and fuel cells are more accommodating to the fuel pressure issue, generally requiring under 50 psig. Reciprocating engines operating on diesel fuel storage do not have fuel pressure as an issue, however, there may be special permitting requirements for on-site fuel storage.

Diesel engines should be considered where natural gas is not available or very expensive. Diesel engines have excellent part load operating characteristics and high power densities. In most localities, environmental regulations have largely restricted their use for CHP. In California and elsewhere in the U.S., diesel engines are almost exclusively used for emergency power or where uninterrupted power supply is needed such as in hospitals and critical data operating centers. As emergency generators, diesel engines can be started and achieve full power in a relatively short period of time.

2.0 Market Potential for Combined Heat and Power

CHP Development in California

The growth of Combined Heat and Power (CHP) in California in the years after the Public Utilities Regulatory Policy Act (PURPA) of 1978 was driven by a regulatory environment and cost of energy assumptions that have significantly changed in the last few years. The decline of lucrative utility purchase contracts, lower relative energy prices and uncertainties of restructuring require customers, regulators and the financial community to look at CHP in a new light. The opportunities for CHP can be highlighted by focusing on some of the fundamental changes brought about by electric industry restructuring and how CHP can serve customers and the public interest in the future.

There are two changes that are the basis of optimism for the future of CHP. First, there have been technological improvements to increase efficiencies and reduce environmental impacts from existing CHP technologies. There have also been an expansion in the sizes and types of technologies available. These technologies are covered in detail in Technology Characterization, Section 1 of this Market Assessment Report.

The second major change affecting CHP in California is electric industry restructuring. It has fundamentally altered the incentives for investing in generation. No longer are vertically integrated utilities guaranteed a reasonable rate of return on all prudent investments. Utilities are being encouraged to unbundle generation and affiliated services from their service package. Customers have a choice of suppliers, or they can supply themselves. Some customers are aggregating for improved service offerings at lower prices. There are new opportunities and new risks for customers and energy services companies in this changing picture. CHP now has the potential to match customer needs more accurately than is possible through traditional central supply.

Section 2-1 will discuss the technical promise of CHP, and how that promise has been realized or disregarded in the regulatory environment of the last twenty years. Section 2-2 is a technical review of existing CHP in California and Section 2-3 is a quantitative discussion of the remaining market potential.

2.1 The Technical Promise of CHP

Power generation systems create large amounts of heat in the process of converting fuel into electricity. For the average power plant, over two thirds of the energy content of the input fuel is converted to heat and wasted. As an alternative, an end-user with significant thermal and power needs can generate both its thermal and electrical energy in a single combined heat and power system located at or near its facility. CHP, also called cogeneration, can significantly increase the efficiency of energy utilization, reduce emissions of criteria pollutants and CO_2, and lower operating costs for industrial, commercial and institutional users. CHP has been used by some industries such as pulp and paper and petroleum for over 100 years to meet their steam and power needs.

Figure 2-1.1 CHP versus Separate Heat and Power

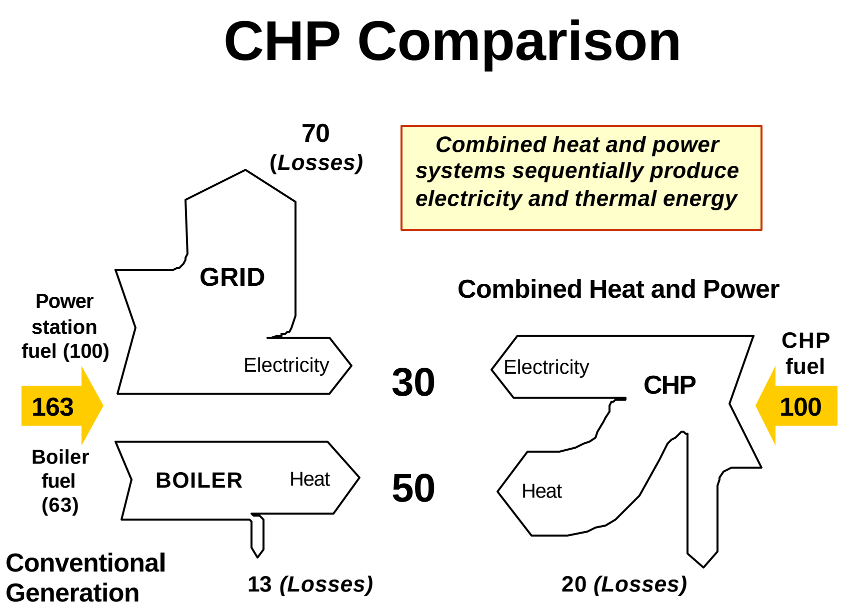


Figure 2-1.1 above shows how out of 100 units of input fuel, CHP converts 80 to useful work, 30 to electricity and 50 to heat to a boiler. Traditional separated heat and power components require 163 units of energy to accomplish the same end use tasks[3].

CHP Development under PURPA

PURPA was enacted during the Carter Administration as a reaction to the "energy crisis" and the perception of a short supply of fossil energy. Its purpose was to increase supply-side energy conservation (efficiency) and to diversify fuel resources. The cogeneration rules in PURPA were designed to increase efficiency of fuel use by removing regulatory and institutional barriers to the development of CHP. PURPA stimulated the market, primarily for large CHP systems, by requiring utilities to interconnect with qualified CHP facilities, provide backup power at reasonable rates, and purchase any excess electricity at the same rate the utilities would have had to pay to generate it themselves, the utilities' avoided costs. PURPA

[3] Based on Tina Kaarsberg and Joseph Roop, Carbon and Energy Savings from Combined Heat and Power: A Closer Look, 1999. These are national averages for existing installed boilers and central generating plants, illustrative of but not identical to California averages.

successfully removed barriers to CHP. Total U.S. capacity increased from about 10,000 MW in 1980 to over 44,000 MW in 1995—but it also encouraged capacity sales in some regions of the country that exceeded incremental requirements. Lucrative power contracts spurred development of so-called "PURPA machines" during this period that often maximized electric output at the expense of overall efficiency.

To qualify for PURPA benefits small power producers and cogenerators had to file with the Federal Energy Regulatory Commission (FERC) as "Qualifying Facilities" or QFs. The QFs had to meet minimum useful thermal energy and overall efficiency requirements. Utilities were required to purchase power from QFs at a rate not to exceed their own avoided cost. Purchasing power at avoided cost was designed to give assurance that the public would not pay more for power from QFs than it did from the utilities.

California's investor-owned utilities issued Interim Standard Offer Contracts to QFs for power purchases. The Interim Standard Offer contracts for long-term energy and capacity are known as Interim Standard Offer 4 (ISO4). ISO4 contracts provided the option for some QFs to obtain fixed energy prices for up to 10 years, after which energy prices revert to the short-run avoided cost of the purchasing utility. PURPA and ISO4 contracts fostered a dynamic CHP industry in California from the mid-1980s to the early 1990s. Over 5200MW, representing over 81% of the CHP in California, came on line during the decade from 1982 to 1991.

The Market Levels Off

Lower avoided costs and increasing utility resistance led to a decline in the CHP market in the mid-1990s. Utility resistance led to imposition of market barriers to non-QF CHP and lower avoided cost became the basis on which utilities fought new QF activity. The original fixed forecast energy prices were developed based on short run avoided costs in 1983. A few years later, it became evident that the forecasts and reality were moving in opposite directions, with forecasts going up and costs going down. Since PURPA was enacted, avoided costs in California have dropped from between $0.04 and $0.07/kWh to approximately $0.025/kWh, due to low natural gas prices and improved technologies.

Southern California Edison and San Diego Gas and Electric petitioned the FERC to void a 1993 California PURPA auction. The companies claimed that the California Public Utilities Commission (CPUC) had forced them to accept several hundred megawatts of renewable energy (geothermal wind) priced at above 6 cents per kwh compared to available new gas-fired capacity at 4 cents per kWh. In a landmark decision, the FERC agreed with the utilities that, given the emerging competitive landscape, avoided-cost determinations had to be open to all sellers to accurately measure the avoided cost. The FERC's decision had a chilling effect on the CHP market in California and new PURPA auctions were put on hold[4].

[4] Federal Energy Regulatory Commission, *Order on Petitions for Enforcement Action Pursuant to Section 210(h) of PURPA*, **70 FERC 61666 at 61667, 61672**, 1995.

The future of existing QFs is not certain, but it seems clear that at the end of the ten-year fixed contracts, they will experience significant reductions in revenue. Some QFs may choose to stop generating and resume purchasing power from their distribution utility or from the market.

New Opportunities in a Restructured Electricity Market

A new electricity market opened in California on March 31, 1998 giving direct access, that is, a choice of energy service providers, to all electricity customers in the state located within the service territory of one of the Utility Distribution Companies[5] (UDCs), with the purchase of a special meter.[6] Direct access by customers to non-utility Energy Service Providers (ESPs) for electricity was made possible by the passage in September of 1996 of California electricity restructuring legislation contained in Assembly Bill 1890. Under AB1890, the UDCs are required to make all their power purchases from the state-created market for power called the Power Exchange (PX). Any generators of electricity are allowed to bid their power into this wholesale PX auction market. An Independent System Operator (ISO) was also set up to manage the California transmission system and to ensure the availability of power.

The restructuring plan also provides for divestiture of UDC generating assets, UDC stranded asset recovery and preservation of public interest programs. Each of these components has an effect on the market for distributed energy resources, including CHP.

Divestiture

As part of restructuring, the utilities have been encouraged to divest themselves of 50% of their generation portfolio in order to reduce the opportunity to exercise market power. They have opted for strategic reasons to over-comply and sell most of their generation capacity. Notable exceptions are the SCE hydro (1,150 MW), SCE nuclear (1,600 MW), SCE out-of-state (5,000 MW of fossil and nuclear), PG&E nuclear (2,160 MW), and PG&E and SCE power purchase and QF contracts. The balance of the central station generation has moved into private hands, and there is indication that the new owners will repower or otherwise modify the units to operate more efficiently. There are many opportunities to sell the energy from these plants as wholesale bulk power through the PX or other exchange, or to serve the ancillary services market of the ISO, as well as traditional bilateral short or long term contracts with UDCs. Owners will operate the plants to maximize profits on energy sales, not to obtain a fair rate of return under a managed regulatory regime.

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[5] Pacific Gas & Electric (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E)

[6] Direct access is withheld from customers of municipal utilities except upon a decision by the municipality to open its territory to competition.

Stranded Asset Recovery

UDCs are allowed under the California restructuring to recover 100% of their stranded asset costs, investments made in a past regulatory environment that would hamper future UDC competitiveness. Major components of the cost include the construction and operation of the nuclear generating stations and PURPA standard offer contracts. Stranded assets are recovered through a Competition Transition Charge (CTC) that appears on each customer's bill. New generators (those committed after December 20, 1995) must also pay CTC, based on metered output of the generator. CTC is not charged for customer demand side energy efficiency initiatives or for photovoltaic (PV) systems smaller than 10kW. All CHP projects will have to pay CTC until June 30, 2000 when these projects become exempt. Rates of all customers are frozen at existing levels until CTC is paid off; lower energy prices for the customer result in faster CTC collection, and vice-versa. Sales of the UDC power plants, most of them transacted quickly and at a premium over book value, have also paid down stranded asset totals[7]. Early payment of stranded costs does not effect the rate at which CTC is collected, it hastens the date at which current CTC charges will disappear. San Diego Gas and Electric (SDG&E) paid off its CTC in July of 1999. Pacific Gas and Electric (PG&E) may pay its CTC before July 2000, depending on the sale of its hydro-electric power generating assets.

Public Interest Programs

Public interest programs, such as energy efficiency, renewable energy sources and energy research, continue to be funded under AB1890. Control of the funds generated by the public goods charge, $201 million in 1998, lies not with the UDC, but with a new entity called the California Board of Energy Efficiency (CBEE). The Board is appointed by the CPUC and has been funded through the year 2000. The energy efficiency funds do not currently reward CHP projects directly; fuel switching is disallowed, and no incentive is available for generating electricity onsite or for heat recovery from generation processes. The indirect potential benefit to CHP from the public interest monies is through energy research.

Competition

Although retail sale of power has been stagnant in California, the wholesale market is extremely active. As mentioned above, most fossil units in the state are now in the hands of private owners, mostly utilities headquartered in other states, who plan to produce power as cheaply as possible and sell it at a profit to the PX. Recent capacity constraints, the high price of electricity in California and the restructuring legislation, has created a flourishing wholesale market for power, and has encouraged siting plans for new merchant power. The CEC has anticipated and potential siting cases before it for 14,360 MW of combined cycle power plants[8].

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[7] Kathryn Kranhold, "As Industry Changes, Utilities Find Surge of Interest in Power Plants", Wall Street Journal, October 26, 1998

[8] Correspondence with Matt Layton of CEC, August, 1999.

The impact of these changes on the future of CHP in California is still unclear. Reduction of retail electricity prices brought about by competition in the wholesale markets may reduce the electric rates paid by large industrials, decreasing the value of power generated on-site and lengthening the payback on CHP projects. Large CHP installations depending on excess power sales will have to compete with the other wholesale generators. The central station and new merchant generators may have dispatchability and cost advantages over CHP.

At the same time, small-to-medium-sized industrial facilities and commercial/ institutional facilities may see their peak electricity rates increase, increasing the value of on-peak use of CHP. Some customers may value the added reliability of CHP, others may be interested in the sale of CHP ancillary services. In any case, customers who are considering installing CHP will need to match their internal electric and heat loads with the value of energy to maximize the return on CHP. Coupled with improvements in technologies and pending policy initiatives aimed at encouraging CHP, the customer base for economic within-the-fence CHP systems has the potential to expand considerably as an important subset of distributed generation.

Although wholesale competition and customer electricity prices are key to CHP project economics, comparing distributed resources with the central-power busbar costs is no longer the objective. Competing with the cost of energy and energy services as delivered at to the end user is the true benchmark. Busbar cost from a power plant could be low, yet the delivered price, after including the T&D cost, cost of congestion, timing, reliability, availability, power quality may be high enough for the user to realize savings through CHP. This distinction will be a criterion in establishing the true market potential. Also, this change in benchmark also makes it difficult to project market potential since all the parameters which determine the delivered cost of electricity are still evolving with the unbundling process.

The market for CHP in California appears to be both helped and hindered by the passage of AB 1890. The changes brought by restructuring, and the publicity surrounding them, has increased the customer awareness of the options available for managing electricity costs. CHP has a new opportunity to meet the energy needs of customers more effectively and efficiently than has been possible heretofore. The new opportunity for CHP has attracted growing interest among policymakers to promote an expanded role for CHP and other distributed generation technologies. CHP opportunities need to be carefully analyzed to ensure cost effective implementation and applications. To effectively compete in these markets CHP will also have to overcome barriers that existed before restructuring, embedded in the established behaviors of the UDCs and regulatory agencies. These barriers need to be addressed before CHP can deliver the full range of its benefits.

Potential Benefits of CHP

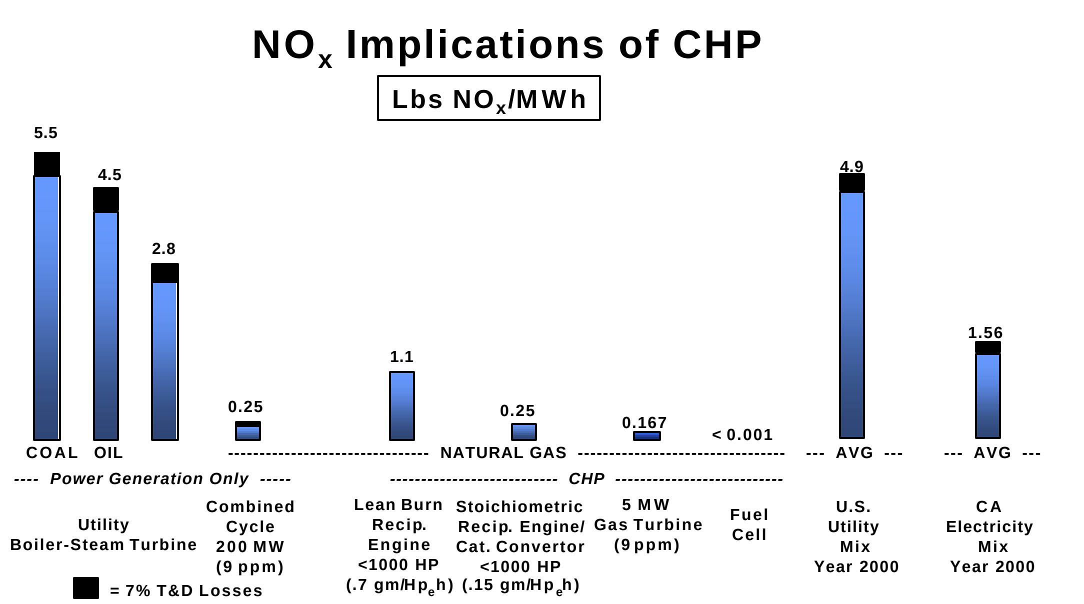
Efficiency

Power generation systems create large amounts of heat in the process of converting fuel into electricity. Over two-thirds of the energy content of the input fuel is converted to heat and wasted in many older central generating plants. As an alternative, an end-user with significant thermal and power needs can generate both its thermal and electrical energy in a single combined heat and power system located at or near its facility. Figure 2-1.1 shows how a well-balanced CHP system outperforms a traditional remote electricity supply and on-site boiler combination. The chart illustrates that out of 100 units of input fuel, CHP converts 80 to useful work, 30 to electricity and 50 to steam or some other useful thermal output; traditional separated heat and power components require 163 units of energy to accomplish the same end use tasks. While future central station plants will be able to generate electricity more efficiently than the 30 % average rate used in developing the chart, CHP installations with proper thermal / electric balance have design efficiencies of 80 - 90 % and will still result in significant overall energy savings. On-site use of CHP also reduces transmission and distribution system line losses to zero from typical central unit line losses of 4% to 12%. (We have used a figure of 7% line losses consistently in this report.)

Emissions Reductions

By increasing the efficiency of energy use, CHP can significantly reduce emissions of criteria pollutants such as NOx and SO2, and non-criteria greenhouse gases, such as CO_2.

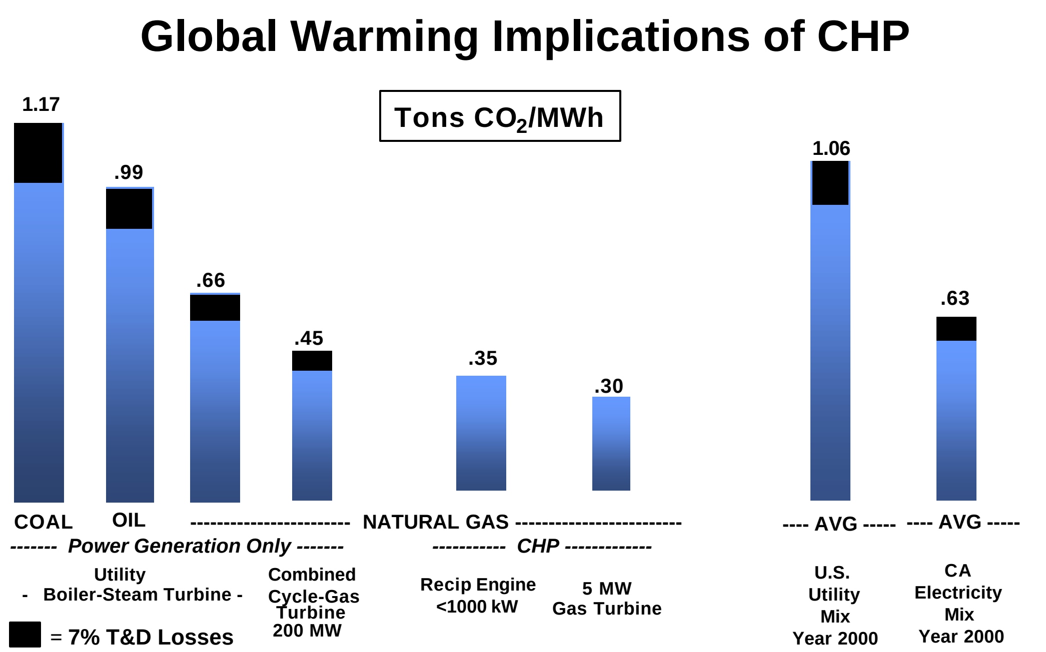
Figure 2-1.2. Comparison of NOx Emissions from Electricity Generating



Source: (1) GRI Report Light Duty Vehicle Full Fuel Cycle Emissions Analysis, 1994
(2) Gas Turbine Environmental Analysis and Policy Considerations, Onsite Energy, 1997
(3) Sierra Energy and Risk Assessment, SoCalGas UEG Customer End-Use Specific Avoided Energy GT&D Costs and Emissions, 1997

Figures 2-1.2 and 2-1.3 show NOx and CO_2 emissions comparisons respectively by power generation technology and fuel type. While reductions in both NOx and CO_2 result from moving from solid and liquid fuels to natural gas, the figures show the added reductions that efficiency can provide. CHP technologies can significantly reduce emissions and compare favorably to advanced low emission central station technologies such as gas-fired combined cycle. The California electricity mix emissions in the figures include both in-state and out-of-state generation.

Figure 2-1.3. Comparison of CO_2 Emissions from Electricity Generating

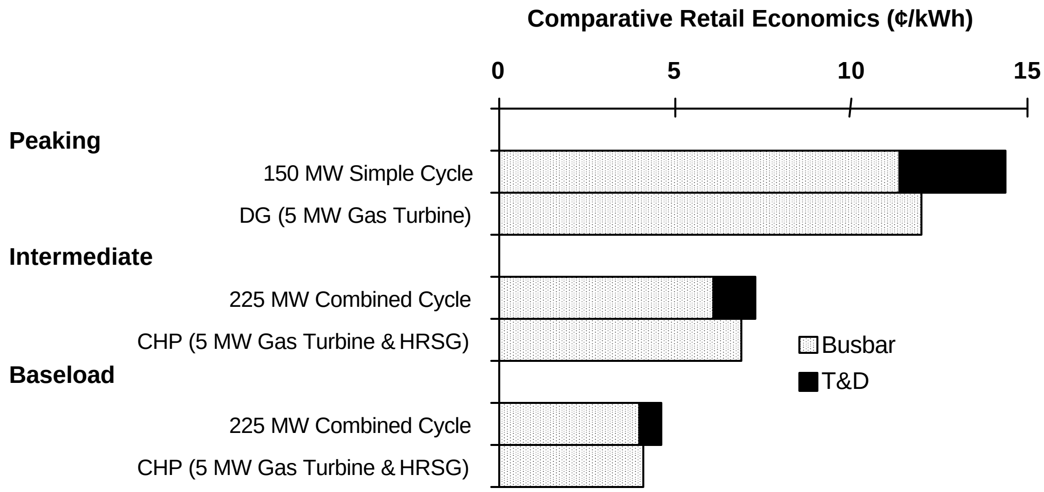


Source: (1) GRI Report Light Duty Vehicle Full Fuel Cycle Emissions Analysis, 1994
(2) Gas Turbine Environmental Analysis and Policy Considerations, Onsite Energy, 1997
(3) Sierra Energy and Risk Assessment, SoCalGas UEG Customer End-Use Specific Avoided Energy GT&D Costs and Emissions, 1997

Economics

The primary economic driver for CHP is production of power at rates that are lower than the utility's delivered price. Figure 2-1-4 demonstrates graphically how CHP compares with traditional central station generation combined with the necessary transmission and distribution (T&D) to move the power to the load. California companies currently have average commercial and industrial electricity rates that are higher than 80 to 90% of all customers in the U.S. -- $0.097/kWh for commercial users and $0.063/kWh for industrials.

Figure 2-1.4 Cost of Power from On-Site CHP versus Delivered Price



By comparison, the cost to produce electricity from a CHP system using an industrial-sized gas turbine, including fuel, capital and operation and maintenance (O&M) expenses, is less than $0.04/kWh for baseload purposes. This cost compares favorably against a baseload central-station combined-cycle plant at the busbar even before T&D charges are added in. As shown in Figure 2-1.4, CHP also can compete against large simple cycle gas turbine plants for intermediate load purposes and peaking power once T&D costs are factored in. The T&D charges represented in this exhibit include 7% line losses and a $150/kW investment.

The cost of CHP varies, of course, by application, technology, and grid circumstances, but as this example illustrates, the economic fundamentals will frequently favor CHP. In a restructured environment, users may also begin to place significant economic value on the stand-by capability and increased power reliability that CHP can provide, further enhancing the potential economic benefits of on-site CHP.

Ancillary benefits

In a restructured electric industry, CHP and other distributed generation options can offer grid support to the distribution utility. They also give energy service providers (ESPs) or users the ability to offer ancillary services to the system, including:

- Voltage and frequency support to enhance reliability and power quality;
- Avoidance or deferral of high cost, long lead time T&D upgrades;
- Bulk power risk management;
- Reduced line losses, reactive power control;
- Outage cost savings;
- Reduced central station generating reserve requirements;
- Transmission capacity release

Energy services providers are working now to determine the quantity and value of benefits derived from grid support and ancillary services that accrue from installing CHP and other DG systems.

CHP offers a customer enhanced reliability, operational and load management flexibility (when also connected to the grid), ability to arbitrage electric and gas prices, and energy management, including peak shaving and possibilities for enhanced thermal energy storage. The value of these benefits will depend on the characteristics of the facility, the form and amount of energy it uses, the load profile, the rate tariffs, prices of electricity and gas and other factors. A facility making a CHP purchase decision will have to consider the ancillary benefits, including the revenue stream possible from sale of the transmission and distribution benefits to the ISO and reduced operating costs, along with the other costs and benefits of the project.

Market Barriers

Historically, CHP and other forms of on-site generation have faced severe market and regulatory barriers. These include utility practices and electricity rate designs that discourage on-site generation, lengthy and costly environmental permitting and siting processes, uneven tax treatment of on-site generation assets and high customer hurdle rates for energy related investments.

Utility Practices Barrier: Grid Interconnection

The optimal economic use of CHP for most customers requires integration with the utility grid for back-up, supplemental power needs, and, in selected cases, for marketing or wheeling generated power. Systems isolated from the grid generally are more capital-cost intensive and provider fewer benefits to customers and the grid than do grid-interconnected systems. Therefore, the key to the ultimate market success of CHP is the ability to safely, reliably and economically interconnect with the existing utility grid system. And if properly deployed, CHP systems can enhance system reliability, decrease the likelihood for system outage and contribute to the maintenance of the stability of the system, *i.e.*, correct voltage and current characteristics system-wide. However, grid interconnection requirements for self-generators, as they exist today, are a significant barrier to more widespread economic deployment of CHP.

Interconnect requirements for on-site generation have an important function. They ensure that the safety and reliability of the electric grid is protected, and the UDCs have ultimate responsibility for system safety and reliability. For the UDCs, there are three primary issues. First, the safety of the line personnel must be maintained at all times. UDCs must be assured that CHP and other on-site generation facilities cannot feed power to a line that has been taken out of service for maintenance or as the result of damage. Second, the safety of the equipment must not be compromised. This directly implies that a CHP system failure must not result in damage to the utility system to which it is connected or to other customers. And third, the reliability of the distribution system must not be compromised.

There is no question about the importance and legitimacy of these basic concerns. However, the existing UDC requirements to address these issues vary from utility to utility. There is no standard approach that manufacturers and developers can follow. Compliance often requires custom engineering and lengthy negotiations that add cost and time to system installation. These requirements can be especially burdensome to smaller systems (under 500 kW). Non-standard requirements also make it difficult for equipment manufacturers to design and produce modular packages. Whether the technology is a micro-turbine, fuel cell, engine-generator set, or industrial gas turbine, the lack of consistent interconnection standards hampers the efforts of manufacturers to realize economies of scale and discourages the economic business case for CHP.

A review of the major California UDC interconnect procedural requirements shows a long and involved process. This process requires site-by-site analysis by both the developer and the UDC, design of an appropriate package *for that unique site*, and site inspection and testing, in many cases by a third party, before approval to operate is granted. These interconnection studies can cost between $2,000 and $20,000 or more, depending on the voltage of the project and many other factors. The study may be lengthy and the outcome is completely uncertain at present. The amount and type of protection is currently completely at the discretion of the UDC, which may have a competitive interest in the outcome. The actual system protection required by the UDC can easily make an otherwise cost effective project uneconomic. This is one of the major barriers to deployment of CHP and all other distributed energy resources.

Utility Practices Barrier: Standby Charges

On-site CHP usually requires back-up power to cover downtime for routine system maintenance or for unplanned outages. Standby rates are a fixed monthly charge for reserved generation and distribution capacity to provide back-up power. Generally, standby service is billed based on the rated capacity of the CHP unit or customer peak demand, whichever is lower. As an example, an on-site CHP system in SCE territory will currently pay $6.40/kW for standby service (the standby rate contains a CTC component, which will disappear after CTC is recovered; the customer in this example will still pay a standby fee of $3.74/kW after the CTC is recovered under the current SCE tariff). This rate is essentially equal to the facilities related component of the demand charge.

Should a customer actually require back-up power, additional charges are invoked that reflect the cost of supplying power to a self-generation customer during an outage. These back-up charges often contain an additional demand charge. Most California IOUs have high monthly electric demand charges that are levied against self-generation in their entirety even if only needed for a brief time period during an unscheduled outage in a month (even as briefly as 15 minutes). This is in addition to an energy charge that is based on kWh used during the outage. Unreasonably high costs for these services (standby rates and back-up charges) has been a barrier to on-site generation in the past. As restructuring proceeds, these charges as currently configured may not necessarily reflect a utility's actual cost, nor do they necessarily reflect the diversity of CHP resources on the system.

Table 2-1.1 shows an example of the standby and back-up charges incurred by a typical industrial CHP customer which is 92% available, but which uses standby at least 15 minutes per month. The California case is for an SDG&E customer and includes monthly demand charges applied to the entire month even though the outages are of short duration. Illinois and Texas are examples of states that have determined that monthly demand charges are inappropriate for backup, and in those states, back-up charges are for the energy component only.

Table 2-1.1 Standby/Back-up Charges

Annual Back-up/Standby Charges	California Case	Illinois/Texas Case
Outage Hours	456	456
Summer Outage Hours	190	190
Winter Outage Hours	266	266
Summer Outage Energy Charge	$14,668	$14,668
Winter Outage Energy Charge	$14,613	$14,613
Summer Outage Demand Charge	$121,300	
Winter Outage Demand Charge	$52,955	
Standby Charge	(Included in above)	$45,000
Total Back-up/Standby Charges	$203,536	$74,281

The economic impact of these two approaches is illustrated in Table 2-1.2 for a typical

Table 2-1.2 Impact of Back-up/Standby Charges on CHP Economics

Annual Costs	**Grid Purchase**	**California Case**	**Illinois/Texas Case**
Capital Carrying Charge		$130,000	$130,000
Fuel Cost		$157,320	$157,320
Cogeneration Heat Credit		($78,660)	($78,660)
O&M Cost		$62,928	$62,928
Back-up/Standby Power		$203,536	$74,281
Total Cost	$441,309	$475,124	$345,869
Total Electric Generated (kWh)		5,244,000	5,244,000
Total Electric Bought (kWh)	5,847,000	603,000	603,000
Average Power Cost ($/kWh)	$0.0755	$0.0906	$0.0660

industrial customer.[9] It is evident that high charges such as these can be debilitating to self-generation economics and introduces an uncertainty that makes capital investors wary.

Utility Policy Barrier: Stranded Assets and CTCs and Departing Load

Under most state restructuring plans utilities are being permitted to recover stranded assets that were incurred on behalf of their customers under previous regulatory arrangements. In many states, tariffs for stranded asset recovery are non-bypassable, and customers installing on-site generation pay a fee on the kWh they generate as well as purchase, or they may be charged a one time exit fee equal to their share of the expected stranded cost if they elect to leave the grid. Other states have decided to charge on-site generators exit fees for potentially unused distribution assets even after stranded generation and transmission assets are completely recovered through the restructuring transition period. However, these same states do not attempt to apply such charges to kWh reductions resulting from demand side management or other energy efficiency investments by the customer. Application of these charges to efficient on-site generation projects can significantly impact the economics and delay widespread implementation of CHP.

AB1890 gives the investor-owned utilities in California the same opportunity to reasonably recover their stranded costs, which are those generation investments they made that are above the competitive market. The stranded costs are recovered through a CTC (Competition Transition Charge) a charge per kilowatt hour (usually) applied on all customer bills to pay down the stranded assets. However, in California , CHP, unlike any other form of distributed generation, has three potential exemptions from the CTC. First, if the CHP system was operational before December 1996; second, if the system becomes operational after June 2000; and third, if the system comes on line between 12-1996 and 7-2000 and has full "blackstart capability", which is the ability to start up and run without any support from the grid.

A customer that builds a CHP system which is not exempt (built between 12/96 and 7/00 without proving blackstart capability) and which relies on this power will be billed a departing load charge. This charge, sometimes called an exit fee, is calculated by the utility as the difference between what the customer would have paid if they had stayed on the system and what the customer pays after departing. The customer pays departing load charges monthly in addition to any other applicable tariffs. This departing load charge applies even if the customer supplies 100% of its power on-site.

While the exemptions provided for CHP and the acceleration in recovering stranded assets has lessened the impact of stranded asset recovery on the CHP market in California, it remains a serious barrier in many other states. It should also be noted that several commenters

[9] This example assumes a CHP system capacity of 1000 kW, Heat Rate (Btu/kWh)-HHV10,000, Useful Heat per kWh of 3500, Gas Price ($/MMBtu) of $3, Boiler Efficiency of 70%, O&M ($/kWh) of $0.0120, Availability of 92%, Capital Cost ($/kW) of $1000, Capital Recovery Factor of 13%, Full Load Hours 5700.

representing the utility industry recommended imposing exit fees and/or a new stranded distribution cost recovery charge on customers installing on-site generation as part of their initial filings in the recent California Public Utility Commission's OIR on distributed generation.

Environmental Barriers

The most notable environmental barrier for CHP is the air quality permitting process and regulatory requirements. The air quality permitting process for various CHP technologies can be long, complex and costly. New CHP installations using turbines and IC engines are typically required to meet stringent NOx emission standards not required of existing equipment or central station generating plants. These factors result in additional costs and time that burden CHP economics.

The complexity of permitting results from regulatory requirements that differ among the various air districts. The lengthy permitting process results from the evaluation of New Source Review (NSR) requirements such as best available control technology (BACT) and lowest achievable emission rate (LAER), as well as addressing emission increases that must be offset by emission reduction credits (ERCs). The costly component of air quality permitting not only results from the lengthy permitting process but the potential need to install more costly controls and/or the need to purchase ERCs to offset emissions.

The air quality regulatory requirements differ from district to district because not all districts have the same rules to implement their attainment strategy plans. Districts that exceed the ozone standards have more stringent permitting requirements, as well as source specific requirements, compared to the requirements of districts that meet the ozone standards. Therefore, approaching the permit process requires complying with local standards and regulations and typically requires a customized approach for each district. Some districts may require more information than others, processing fees may be more expensive and air toxics impacts may be of concern in certain areas. Furthermore, regulations continue to change as technology improves and as the district approaches attainment, or conversely as the district's air quality worsens.

The permitting process can be lengthy and costly particularly for CHP projects requiring NSR permitting. When an emission standard and/or control technology is demonstrated in the field, districts tend to adopt the most recent and lowest standard as the benchmark for meeting emission standards. For example, with respect to gas turbines, regardless of the size (e.g., MW), the same type of controls and emission standards are imposed on the smaller units as are imposed on much larger turbines, even though there may be a relatively high cost for control installations. Demonstrating that a type of control technology is not feasible or not cost-effective can result in many iterations and negotiations with the local air district, as well as oversight state and federal agencies. With respect to emission standards, typically concentration rates (ppm) are set at emission standards, and these generally do not reflect the resulting efficiencies associated with thermal output; that is, output-based standards are not set for CHP-type sources (i.e., lb/MW-hr, including power and thermal output) that give credit to the high efficiency benefits of CHP. Additionally, depending on the project configuration, location and aggregate emissions of a CHP project, emission offsets may be required. This can be costly if the local supply of offsets is low; sellers may increase their sale price. With ongoing merchant power plant development in several districts throughout California that are potential candidates for benefiting from CHP, the emission offset issue may become a much more costly item in the permitting process.

Although CHP has provided environmental benefits historically, those benefits have not been accurately quantified to date and are not currently captured or accounted for in the permitting process. The grid emission reductions are not captured in any existing emission trading programs in California. Regulators remain skeptical of trading uncertain regional emission reductions for more certain local air quality impacts. In CHP installations where boiler offsets are created by taking an existing boiler off-line, CHP has the advantage of using those emission offsets for the CHP permit instead of having to pursue offsets in the open trading market. Since new CHP technologies are clean and efficient, credits from the boiler may be adequate to cover all the offset need while meeting thermal demands and generating electricity for internal or offsite use.

Financial Barriers

Inconsistent tax treatment of CHP investments is an additional hurdle to widespread market development. On-site generation systems do not fall into a specific tax depreciation category. Distributed generation can qualify for one of several categories depending on configuration and ownership, so that the resulting depreciation period can range from 5 to 39 years. Existing depreciation policies may foreclose certain ownership arrangements for on-site generation, increasing the difficulty of raising capital and discouraging development. Industrial depreciation schedules ramp down over a fifteen year life of equipment; commercial technologies have 25-35 year depreciation period. This disparity puts CHP at a competitive disadvantage when compared to central station power. The rationale was that turbines used for generation were exhibiting lifetimes of 25 years and greater in utilities where turbines were used only to provide peaking power.[10] This assumption, however, is incorrect for many potential CHP applications. Some members of the distributed generation community believe that a 5 to 7 year depreciation schedule would more accurately reflect the economic life of on-site generation equipment

There are two initiatives underway at the federal level that would move toward a more fair tax treatment of CHP. DOE and EPA have been working with the Department of Treasury to review existing depreciation categories for on-site generation equipment. Treasury is considering allowing on-site equipment in buildings to qualify for a 15 year depreciation schedule, similar to on-site generation equipment in industrial applications. Treasury has also

[10] Steve Bernow and Michael Ruth, "Combined Heat and Power Systems Provide a Cost-Effective Opportunity for Carbon Reductions", Tellus Institute Newsletter, Vol. 7, No. 1 - March 1999, p2.

indicated that it will be reviewing of depreciation schedules for on-site generating equipment in general, and may make recommendations for changes within 12 months. The Administration has also proposed an investment tax credit for CHP as part of its electric restructuring proposal.

Siting Barriers

Siting of CHP equipment involves approval by local agencies and acceptance by the affected communities. Also, the local utility distribution company must approve the grid interconnection, as previously discussed. Agencies include local the fire departments, building departments, planning departments, and air quality districts. On a policy and planning level, local community planning groups may also be involved; such groups monitor the growth issues of their community, as well as actively participate in the land use planning issues. Any CHP sites over 50MW will need to apply for siting review by the CEC.

Most of the concerns and issues involved in the CHP siting process are legitimate land-use planning and community safety issues. The additional burden on CHP come from a lack of knowledge by local authorities and community leaders of CHP technologies. This fact is not helped but hindered by the lack of standards for small CHP equipment. Most CHP equipment operations are fairly straightforward, but some agencies request information that can delay installing the equipment, due to unfamiliarity with the technology. The agencies sometimes require construction 'over-design', which can increase the cost of installation.

As mentioned above, standards are not developed for small CHP units. Fire departments must ensure that there are no fire and safety hazards; with the potential installation of small units in common places such as shopping centers and other general public spaces, such units come under much more scrutiny. Likewise, building and construction inspectors' lack of familiarity with the units can result in requirements that exceed current standards and codes. Because CHP equipment may be required to install air pollution control technology, hazardous materials (e.g., ammonia, sulfuric acid) may be involved. Additional approvals are needed to ensure onsite safety, and proper handling and transport of hazardous materials, as well as ensuring that measures are taken to minimize and eliminate accidental releases of hazardous materials.

For units that may be sited in neighborhood communities, issues that arise include noise and visual/aesthetics, as well as air quality impacts for certain types of CHP units. Land use issues arise if there is a concern with zoning or proximity to sensitive receptors such as schools, hospitals, day care centers and environmentally sensitive areas. For areas that are rapidly growing, amendments must be made to zoning and/or the land use plans if a proposed site is not properly zoned; this can be timely and involve not only an agency review but community acceptance. Depending on the level of community concern and lack of knowledge of CHP technologies and benefits, CHP projects may be faced with meeting conditions beyond standards and requirements governed by agency requirements and be designed as projects prescribed by community needs.

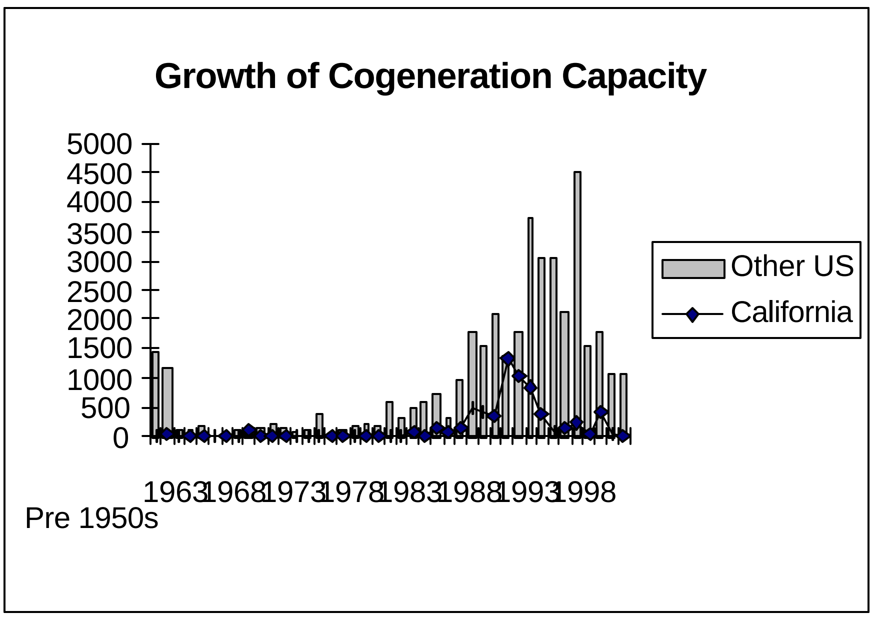
Finally, with respect to air quality impacts, areas that do not meet the ozone standards (e.g., non-attainment areas) typically require more stringent requirements, such as emission controls and emission offsets. In areas that already do not meet the standards, community members may perceive that CHP units are simply adding to the current pollution in the area while providing no additional benefit. In areas that are currently burdened with industrial sources or where a disproportionate amount of pollution exists (e.g., environmental justice areas), there can be more scrutiny of the siting of such units.

2.2 Existing CHP in California

National versus California CHP Capacity

The past history of the U.S. market for CHP could be divided roughly into three phases: the early industrial phase, the PURPA ascendance and the PURPA decline. (See Figures 2-2.1 and 2-2.2[11]). As mentioned previously, the early industrial need for steam and electricity among certain energy intensive industries, such as pulp and paper mills, chemical plants and oil refineries, drove the pre-1970s market. By 1950, there was already an installed capacity of CHP in the U.S. of 1,440 MW. During the fifties, the capacity grew at an annual rate of less than half of one percent. During the sixties, that rate grew to over 2.7% annual growth and at 3.3% during the seventies leading up the passage of PURPA. During the eighties, PURPA nearly doubled that growth rate nationally, driving annual growth to 6.3%. During the nineties, average growth has remained over 5%, but that is mostly due to a large number of installations early in the decade. Growth has tailed off considerably in the last few years.

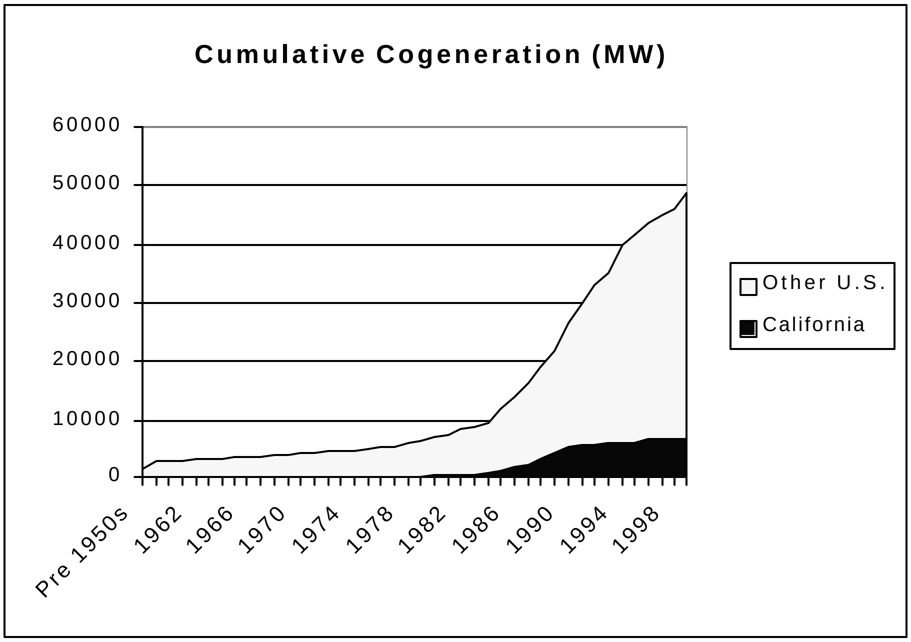
Figure 2-2.1. Annual Growth of Cogeneration, US and CA



[11] All Figures 2-2.1 through 2-2.8 and Tables 2-2.1 through 2-2.3 are based on data from Hagler Bailly Consulting, Inc., *HB Independent Power Database*, 1998.

Growth of CHP in California was dramatically centered around PURPA. Before its passage, there were only 9 cogeneration units operating in the state. Over the next ten years, more than 380 additional cogeneration plants were built. The decade from 1988 to 1997 added over 270

Figure 2-2.2. Cumulative CHP, US and CA



more units. Annual growth in cogeneration capacity went from less than 1% in the seventies to 27% in the eighties. By the nineties, the rate had slowed to just over 4%. In 1998, after nearly sixteen years of double-digit plant additions, only one cogeneration plant was added.

The CHP market decline in California resulted from lower avoided costs for power sold to the grid and increasing utility resistance. Utility resistance led to imposition of market barriers to non-QF CHP and lower avoided cost became the basis on which utilities fought new QF activity. Some cogeneration equipment manufacturers, however, also believe that more stringent state environmental requirements helped to depress the market for CHP in the 1990s.

Had growth in California kept up with the remainder of the United States, the installed cogeneration capacity in the State would be more in the order of 8000 MW rather than the existing 6457 MW. Although growth in cogeneration leveled off in California, the industrial sector still outpaces the rest of the nation, with 33 kW of CHP installed in California per million dollars of shipment value, compared to 13 kW for the rest of the United States.

Historical Reliance on Sales to the Grid

Over 93% of existing CHP in California relies on sales of electricity back to the grid.[12] Some facilities sell all of the electricity they generate, others use a portion on-site and sell the balance.

[12] Hagler Bailly Consulting, Inc., *HB Independent Power Database*, 1998.

This reliance on electricity sales as an economic driver for CHP reflects the impact of PURPA and the initial standard offer contracts developed as a result of that legislation. In a restructured marketplace in which wholesale and retail prices of electricity are expected to decline (see Section 3), the ability of CHP units to sell heat and power to facilities off-site will continue to be an important determinant of success. The market assessment in Section 3 assumes that CHP

Table 2-2.1 CHP Reliance on Power Sales to the Grid

	Sale to Grid		No Sales to Grid	
Technology	MW	Sites	MW	Sites
Boiler/Steam Turb	760.4	33	47.6	8
Combustion Turbine	2,859.0	92	172.9	28
Combined Cycle	2,305.2	36	115.9	3
Recip Engine	113.2	115	81.0	343
Fuel Cell	0.1	2	2.0	8
Totals	6,037.9	278	419.4	390

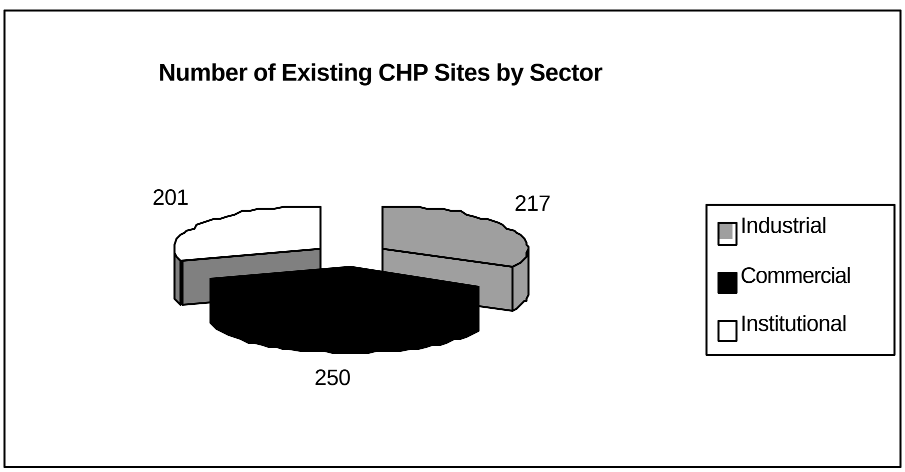
systems will be sized to meet on-site thermal and electric loads, and that these systems must compete against the retail prices for separate heat and power. (A future paper on Market Transformation will discuss the future of CHP heat and power sales, including an analysis of barriers to sales and their impact on market penetration.)

The Disposition of the Existing California CHP Market

Distribution by Sector

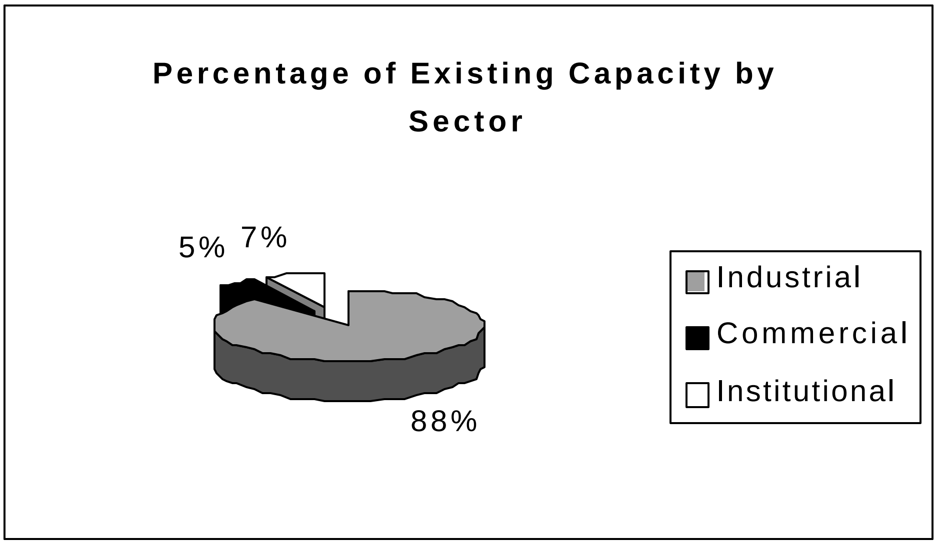
There are currently 668 Combined Heat and Power sites installed in California, with a capacity of approximately 6,457 MW. Although the number of sites is roughly equally distributed

Figure 2-2.3. Existing CHP, Number of Sites by Major Sector



between commercial, industrial and institutional sectors (see Figure 2-2.3), the industrial sector dominates overall CHP capacity. Average industrial installations are much larger in size than the commercial or institutional sectors, averaging over 26 MW per site, for a total of 5,652 MW of installed capacity, while the commercial site average capacity is less than 1.3 MW and the institutional site average capacity is about 2.4 MW, for totals of 323 MW and 482 MW respectively.

Figure 2-2.4. Existing CHP, Share of Capacity by Major Sector



Distribution by Fuel Type

CHP installations in California are dominated by natural gas -- accounting for 600 of the 668 CHP installations and almost 85% of MW capacity. The charts below give the proportional

Table 2-2.2. Existing CHP, Distribution by Fuel Type

Fuel Type	# of Sites	MW Capacity	% of Total
Natural Gas	609	5,479.7	84.9%
Coal	7	313.0	4.8%
Waste Fuels	10	276.1	4.3%
Wood	15	194.1	3.0%
Waste Energy	4	83.0	1.3%
Wood/Waste	2	32.5	0.5%
Fossil Waste	1	27.0	0.4%
Agricultural Waste	2	25.0	0.4%
Biomethane	4	11.7	0.2%
Oil	4	11.6	0.2%
Biomass	3	2.8	0.0%
Propane	7	0.3	0.0%
Municipal Solid Waste	0	0	0.0%
Total	668	6,456.76	100.0%

breakdown. Natural gas CHP installation can be virtually any size, from the smallest reciprocating engine to the largest combined cycle unit. Coal, waste fuels and wood comprise about 5%, 4% and 3%, respectively, making up about 97% of the existing California CHP fuel use. Table 2-2.2 gives a complete breakdown of CHP fuel use.

Distribution by Size

Over 82 % of CHP installations in California are smaller than 10 MW (Figure 2-2.5), yet these sites account for just over 8% of the capacity. The situation is reversed for the large plants. Those sites over 40 MW comprise only 8% of the sites, but account for almost 68% of capacity.

Figure 2-2.5. Existing CHP, Number of Sites by Plant Size

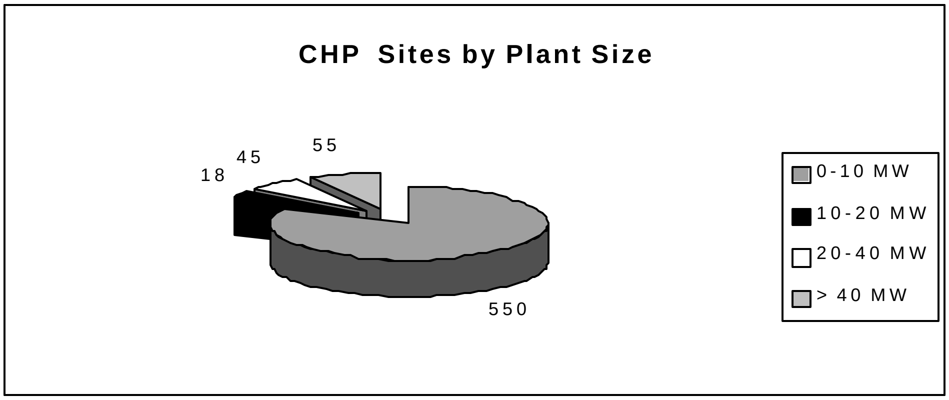
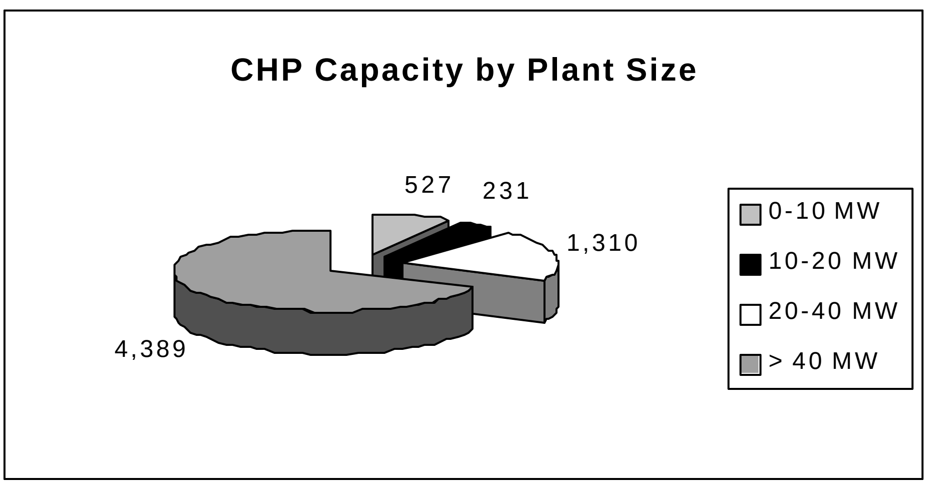


Figure 2-2.6. Existing CHP, MW Capacity by Plant Size



Distribution by Prime Mover

Reciprocating engines comprise 66% of the CHP sites, but only about 2.5% of the MW capacity; combustion turbines represent about 16.7% of the installations, and over 45% of the installed MW capacity.

Figure 2-2.7. Existing CHP, Number of Sites by Technology

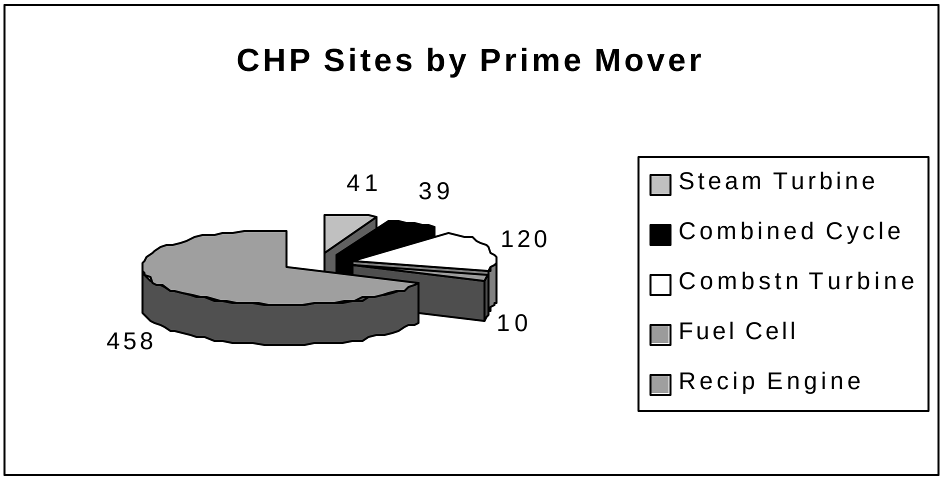
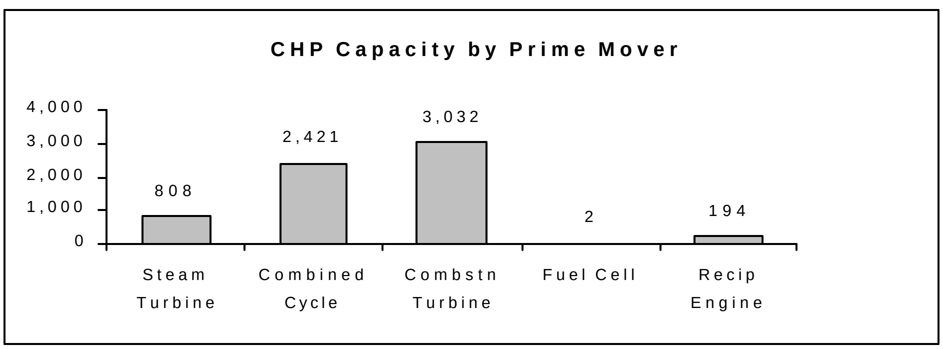


Figure 2-2.8. Existing CHP, MW Capacity by Technology



Distribution by County

Sixty-one percent of the capacity of existing CHP in California lies in three counties: Kern, Los Angeles and Contra Costa. Kern County has 8.4% of the sites and over 29% of the capacity, over 1918 MW. Los Angeles has almost 27% of the CHP sites in the state, with 21% of installed capacity, with over 1368 MW installed. Contra Costa County has less than 2% of the sites, but over 11% of the capacity, with 718 MW of CHP. Most of the Kern county CHP capacity is found in 41 combustion turbines that produce close to 1480 MW. Three large combined cycle units produce another 320 MW. Los Angeles has 14 combined cycle units with about 929 MW of capacity; fifteen combustion turbines add 337 MW; and five boiler driven steam turbines produce 77 MW. LA County has 142 reciprocating engines producing 24.5 additional MW. There are 4 combined cycle units in Contra Costa County that produce 487 MW; 3 combustion turbines add 219 MW.

Kern and Contra Costa Counties have the large average capacity at 34.3 and 59.8MW respectively. In Los Angeles County, due in part to the large number of reciprocating engines, the average installation is 7.7MW.

Table 2-2.3 on the following page gives a complete breakout of all counties and major technologies, with site counts and capacity in MW.

Appendix 2-1 contains a complete listing all existing CHP in California by two-digit SIC for all industrial, commercial and institutional sectors—first, by prime mover, then by fuel type.

Table 2-2.3. Existing CHP, County Listing of Sites and Capacities by Prime

	Total		Boiler/Steam Turbine		Combined Cycle		Combustion Turbine		Fuel Cell		Reciprocating Engine	
County	# of Sites	MW Capacity	# of Site	MW Capacity	# of Site	MW Capacity	# of Site	MW Capacity	# of Site	MW Capacity	# of Site	MW Capacity
Alameda	4	24.38			1	24.2					3	5.879
Amador	1	1.35									1	1.35
Butte	5	35.68			1	28.14					4	7.54
Contra Costa	12	718.12	2	11	4	487.3	3	219			3	0.82
Fresno	25	217.46	2	8.39	3	101.5	6	106.4			14	1.16
Humbolt	1	25.00	1	25								
Imperial	1	7.50	1	7.5								
Kern	56	1,918.56	4	117	3	320.4	41	1479.64			8	1.51
Kings	3	27.14	1	27							2	0.13
Lassen	2	19.34	2	19.34								
Los Angeles	178	1,368.69	5	77	14	928.99	15	337.58	2	0.6	142	24.518
Madera	7	14.16	1	10			2	3.92			4	0.24
Marin	1	0.06									1	0.06
Mendocino	1	15.00	1	15								
Merced	1	8.50									1	8.5
Monterey	17	208.78			1	121	3	78			13	9.78
Napa	1	3.00									1	3
Nevada	1	0.09									1	0.9
Orange	62	32.75					3	6.61	5	0.72	54	25.42
Placer	1	7.50	1	7.5								
Plumas	2	32.00	2	32								
Riverside	30	12.03					1	3.6	1	0.4	28	8.01
Sacramento	3	28.54					1	21			2	7.54
San Benito	2	1.08									2	1.07
San Bernardino	21	194.29	2	120			5	71.25			14	3.01
San Diego	113	265.35	3	107.2	2	58.7	14	51.92			94	47.529
San Francisco	6	40.93			1	13.25	1	13.42			4	14.25
San Joaquim	14	236.97	6	125.2	1	6.5	4	104.43			3	0.83
San Luis Obispo	2	0.54									2	0.54
San Mateo	2	35.60			1	30	1	5.6				
Santa Barbara	14	77.57			1	49	4	27.46	2	0.4	7	0.71
Santa Clara	11	240.99			4	225.7	2	11.8			5	3.48
Santa Cruz	7	31.88			1	28.5					6	3.37
Shasta	4	100.40	3	58.4			1	42				
Sierra	1	20.00	1	20								
Solano	3	2.68									3	2.67
Sonoma	5	1.01									5	1.01
Stanislaus	2	55.40					2	55.4				
Sutter	4	148.26			1	49.5	2	98.7			1	0.06
Trinity	2	17.50	2	17.5								
Tulare	10	2.97									10	2.97
Tuolumne	1	0.01									1	0.01
Ventura	20	243.85	1	3	1	28.4	7	210.64			11	1.81
Yolo	6	7.31					1	3.5			5	3.81
Unknown	2	0.8016									2	0.16
Totals	668	6,456.70	41	808.03	40	2501.08	119	2951.87	10	2.12	458	193.646

Estimation of the Benefits of Existing CHP

CHP provides many benefits over separate heat and power (see Figures 2-1.1 through 2-1.3), including energy savings, reduced air pollution, reduced transmission and distribution line losses, increased fuel efficiency and user economic savings. These benefits are not static, of course, and they depend on the CHP emission rate, central station emission rates, electricity prices and many other factors. Energy customers and regulators need to be able to weigh the benefits of CHP in order to make informed decisions on the use of CHP as a source of power for California. This section will estimate energy savings, economic savings, and NOx and CO_2 reductions from existing CHP in California.

The following estimations are based on a comparison of existing CHP electricity and heat production with electricity available on the grid from central generation units in combination with a gas-fired boiler. (See Appendix 2-2 for details.) Assumptions for energy and economic savings include[13]:

- ❑ Operating hours of 6000 per year[14];
- ❑ Transmission line losses of 7%;
- ❑ Central station efficiency of 9900 Btu/kWh[15];
- ❑ Boiler efficiencies of 60%-90% (depending on size);
- ❑ CHP electricity generation efficiencies of 28%-48% (depending on technology)[16].

Assumptions for user savings include:

- ❑ Electricity price (assumes existing tariff) of $0.058[17];
- ❑ Capital recovery factor of 13.5%;
- ❑ CHP fuel costs of $3 / MMBtu;
- ❑ Standby charges of 15%;

Assumptions for environmental savings include[18]:

- ❑ In-state NOx emissions of 0.46 lbs/MWh;
- ❑ Average of in- and out-of-state NOx emissions of 1.56 lbs/MWh;
- ❑ In-state CO_2 emissions of 872 lbs/MWh;
- ❑ Average of in- and out-of-state CO_2 emissions of 1257 lbs/MWh.

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[13] All figures are estimates of California averages based on contractor experience, unless otherwise marked. All numbers are chosen to represent conservative estimates.

[14] Hagler Bailly Consulting, Inc., *HB Independent Power Database*, 1998, indicates the weighted average of operating hours of all sectors would be over 6400.

[15] Ibid.

[16] Ibid.

[17] A weighted average of UDC commercial and industrial rates.

[18] All emission rates are from Sierra Energy and Risk Assessment, *SoCalGas UEG Customer End-Use Specific Avoided Energy GT&D Costs and Emissions*, 1997

Annual Energy Savings
The estimated total electricity generated by existing CHP systems is over 38 million MWh per year. Savings from transmission and distribution losses amount to over 2.7 million MWh per year, since CHP is located on the site where the electricity is used. Total central station electricity displaced by CHP will equal the on-site generation plus the line loss savings, over 41 million MWh. This represents about 15% of the expected electricity usage in California in 2000[19].

The estimated total net energy savings from all existing CHP in the state of California, based on the above assumptions, is approximately 227 $x10^{12}$ Btu (TBtu). Displaced central station electricity generation accounts for 444 TBtu in energy savings; captured heat creates additional energy savings of 150 TBtu; in turn, the CHP systems consume 367 TBtu. The net energy savings is about 75% of the energy that will be consumed by the Los Angeles Department of Water and Power to serve their electricity usage in the year 2000, or about 7% of the energy consumed for electricity production in that same year statewide[20].

User cost savings
The estimated internal cost for each CHP facility to generate electricity is $0.052 per kWh; there is a thermal credit comprised of the fuel cost savings due to increased thermal efficiency of CHP of $0.012/kWh, making a net cost for power internally generated of $0.041 per kWh. California users of CHP saved over $580 million/year based on generating 38 million MWh of power.

Environmental savings
Emission rates for central stations are changing rapidly, mostly because of the Best Available Retrofit Control Technologies (BARCT) rules that are being implemented state-wide (BARCT is a state-wide air quality rule unique to California that was passed in 1988 to reduce emissions from existing sources). The environmental benefits calculation is a simplification of the physical reality of emissions on the California electric grid, which is extremely complex and not well-understood. It is not known, for example, at what point a benefit will occur when there is a reduction of electricity use somewhere in the system. There is a difference between emission reductions and emission impacts. A ton of NOx in the Mojave Desert does not have the same environmental impact as a ton of NOx in the LA Basin. Therefore, the results of the CHP benefits outlined here should not be taken to correspond with improvements in air quality or movement toward attainment of National Ambient Air Quality Standards[21].

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[19] Ibid.
[20] California Energy Commission, *Electricity Report*, November 1996. Assumes a heat rate of 10,300 and 4% line losses.
[21] Set by the federal Environmental Protection Agency as a target for each state under the Clean Air Act.

The data used for the following environmental savings estimation is derived from data obtained through modeling runs of the ELFIN dispatch model for PG&E and SCE[22]. An unweighted average of PG&E and SCE totals were used for the calculation. The advantage of using outputs of the ELFIN is that it allows discrimination between system average emission rates and marginal, or in this case, incremental emission rates at the margin. The model predicts what the emission rates will be for some increment of emission reductions for units which experience a reduction in operation in response to reduced demand for electricity. This is more accurate than taking a system average because it isolates affected units rather than assuming a system-wide decrease. The modeling runs used were for a flat-load, in other words, a load with high capacity factor, which CHP has. The study used as a basis for this work covers both CO_2 and NOx, so there is a consistency of approach.

The results of the analysis (see Appendix 2-2) allow use of either in-state generation or in-state plus out-of-state generation. The latter gives a more complete picture of the physical reality of emission reductions from CHP, although they require some care in their use. In particular, it is necessary to remember that a ton of NOx reduced over the Grand Canyon does not help the LA Basin (although LA's purchase of power from an Arizona coal plant does impact the air in Arizona). NOx is a regional problem since it contributes under certain conditions to formation of tropospheric ozone which is very much affected by local geography and weather. CO_2, however, is a greenhouse gas (GHG) which contributes to global warming. Reducing a ton of CO_2 emission in Kyoto is as effective at reducing the potential for global warming as reducing a ton of CO_2 in Los Angeles.

The incremental total (in-state and out-of-state) NOx emissions estimate for grid power in 1998 is 1.56 pounds per MWh. The incremental total CO_2 emission rate used here for 1998 is 1257 lbs/MWh. The in-state numbers, for comparison, are 0.46 for NOx and 871.8 for CO_2. For NOx, it may be more reasonable to compare CHP emissions to the in-state rate, since NOx is a regional area of control. CO_2 is a global region of control and so the combined in- and out-of-state rate is preferable. CHP in California has provided NOx reductions of almost 7600 tons per year (based on the in-state rate) and CO_2 reductions over 26 million tons annually (based on the combined in- and out-of-state rate).

Table 2-2.4 shows emissions benefits of CHP by technology, both in-state NOx and total grid CO2 benefits. Negative numbers are emission benefits (reductions), positive numbers are disbenefits. The NOx disbenefit in the boilers is from the solid fuel boilers, those that burn primarily wood or coal. They show high NOx and CO2 emissions, significantly higher than the emissions from the grid.

[22] Sierra Energy and Risk Assessment, *SoCalGas UEG Customer End-Use Specific Avoided Energy GT&D Costs and Emissions*, 1997.

Table 2-2.4 Emissions Benefits of Existing CHP

CHP Technology	In-state NOx tons reduced	Total Grid CO2 tons reduced
Boiler	1866	(3260344)
Combustion Turbine	(5383)	(12232656)
Combined Cycle	(3973)	(9768215)
Fuel Cell	(4)	(8553)
Engine	(113)	(783323)
Totals	**(7,607)**	**(26,053,093)**

Reliability Benefits

Onsite power generation, that is capable of running independently of the grid, increases the reliability of power supply to the site. When the power goes out to a facility, its CHP system can continue to operate to meet the facility load and avoid the associated costs of the outage. This increase in reliability has a value that varies with the type of customer and his risk preference. Not all CHP systems are designed with the capability to operate in a grid independent mode. Those that are provide an additional reliability benefit for the customer. The value of increased reliability due to onsite generation is as follows:

Reliability Benefit = (Expected Outage Hours/yr) x (Outage Cost/hr) x (On-site generation Availability factor)

Overall, the U.S. electric utility system is extremely reliable. Generation and transmission grids are designed for a loss of load probability of less than one day in ten years. Distribution systems are designed to meet the capacity needs of the system, but in some cases, especially rural, residential, and small commercial loads, they are vulnerable to storm damage. In addition, utility systems may operate flawlessly for several years and then suffer a significant problem (storm, earthquake, or loss of a critical transmission system) that blacks out customers for 24 hours or more.

As reliable as the U.S. and California utility system is, when an outage occurs, customers experience damages. A residential customer may experience food spoilage, personal discomfort, and loss of leisure time. A retail store or a restaurant will lose sales. An industrial customer will lose production and may lose the value of work in progress as well. For some customers, like hospitals, the potential outage costs relate to health and safety and are extremely high. For these customers, standby generation is already mandated by code. For other customers, CHP can provide a supplementary reliability benefit. For this analysis, we will assume that expected outages are 3 hours/year for commercial customers and 2 hours/year (or less than one day in ten years) for industrial customers.

Determining outage costs per kilowatt-hour of unserved load for different customer classes can be difficult. There is no established market to value these occurrences. Nevertheless, there has been considerable analysis of this topic by the utility industry that we will use for this analysis. Review of the outage cost literature shows that commercial customers have the highest outage costs, followed by industrial, and finally residential.

Customer Class	Average Outage Costs* $/Unserved kWh
Residential	$1-10
Commercial	$25-60
Industrial	$10-20

* *Customer Demand for Service Reliability: A Synthesis of the Outage Cost Literature*, EPRI P-6510, 1989.

For this analysis, we assumed an average commercial cost of outage of $40/kWh and an average industrial cost of outage of $15/kWh.

Finally, the reliability benefits need to be discounted by the probability that the CHP system is available to serve the load. When grid power goes down the CHP system must be able to pick up the load. For most CHP systems, availability factors run at 95% or greater, so this discounting effect is small.

Sector	Outage Costs $/kWh	Hours /Year	CHP Avail.	Annual Reliability Benefit	Total Existing CHP (MW)	Total Reliability Benefit ($millions)
Commercial	$40	3	95%	$114.00	802	$91.4
Industrial	$15	2	95%	$28.50	5,653	$161.1
Total						$252.5

2.3 The Technical Potential for CHP in California

Technical Potential versus Market Assessment

Market potential is an estimation of market size, constrained only by technological limits—the ability of existing technologies to fit existing customer energy needs. The market potential becomes the starting point for an estimation of actual economic market size. Section 3.0, CHP Market Assessment, includes consideration of the economics of CHP and estimates penetration into the marketplace under two scenarios.

Methodology

CHP is best applied at facilities that have significant and concurrent electric and thermal demands. In the industrial sector, CHP thermal output has traditionally been in the form of steam used for process and for space heating. For commercial and institutional users, thermal output has traditionally been steam or hot water used for space heating and potable water heating. It should be noted that the emerging definition of CHP includes production of mechanical drive/shaft power as well as electricity and additional uses for thermal energy such as heat-activated cooling or direct process heating in contact dryers or heaters. This market study focuses only on the traditional form of electricity and steam/hot water CHP and does not include these expanded applications. As such, the estimates of technical potential generated are limited and conservative, especially in the in the commercial / institutional market.

The methodology employed to develop estimates for the technical potential for CHP in California consisted of the following steps:

- Identify target applications (by SIC) that can support CHP based on their thermal and electric loads and profiles
- Identify the number of establishments in California for each of these SICs
- Develop size profiles for the SICs of interest (i.e., number of establishments by employee size categories
- Estimate average electric and thermal loads for the SICs of interest in each size category
- Estimate CHP potential for each SIC and size category based on number of establishments in each category and applicable electric and thermal loads, and then subtract out existing CHP capacity

A detailed review of the methodology is included in Appendix 2-4.

Industrial Sector

The analysis of CHP potential in the industrial sector was based primarily on energy profiles contained in the Major Industrial Plant Database (MIPD[23]). This database contains detailed

[23] Petroleum Information / Dwights LLC, *Major Industrial Plant Database*, November 1998

electricity and steam use data for the 18,000 largest industrial facilities (generally, those facilities with electric loads > 1 MW) in the United States and covers all manufacturing SICs:

20 Food and kindred products,
22 Textile mill products,
23 Apparel and other textile products,
24 Lumber and wood products,
25 Furniture and fixtures,
26 Paper and allied products,
27 Printing and publishing,
28 Chemicals and allied products,
29 Petroleum and coal products,
30 Rubber and miscellaneous plastics products,
31 Leather and leather products,
32 Stone, clay, glass, and concrete products,
33 Primary metal industries,
34 Fabricated metal products,
35 Industrial machinery and equipment,
36 Electrical and electronic equipment,
37 Transportation equipment,
38 Instruments and related products,
39 Miscellaneous manufacturing industries.

CHP potential was estimated directly for each of the California facilities contained in the MIPD database by analyzing specific steam and electric demands and matching them to CHP system profiles. Estimates were developed for smaller plants not contained in the MIPD by developing size distributions and total energy use characteristics for these plants from information from the California Energy Commission on California electric and gas energy consumption[24] and the state Employment Development Department (EDD) on employment[25]. SIC-specific energy profile and operating information from MIPD were then applied to develop electric and thermal profiles for CHP sizing.

Screening of CHP applicability was conducted on the basis of plant size and electric to thermal, or E/T, ratio. Based on OSEC project experience and analysis of existing CHP capacity, a minimum size limit was placed on industrial facilities of 250kW. Plants with E/T ratios greater than 1.5 were not considered as viable CHP candidates since their thermal loads were too small for CHP to have significant impact on the plant electric demand. Systems were sized to match thermal demand for all plants except when E/T ratios were below 0.4. In these cases, CHP capacity was limited to plant electric demand (i.e., estimates of technical potential are limited to

[24] California Energy Commission, *Quarterly Fuel and Energy Report*, 1997.

[25] California Employment Development Department, *Employment Service form 202 (ES-202)*, September 1997

within the fence CHP applications and assumed no sale of excess power to the grid). The analysis aggregated the results into the following size categories:

- 250kW - 1 MW
- 1 MW - 5 MW
- 5 MW - 20 MW
- 20 MW - 40 MW
- >40 MW

Commercial / Institutional Sector

The analysis of CHP in the commercial and institutional (C&I) sectors was based primarily on energy use profiles developed in the Commercial Energy Profile Database (CEPD[26]) and the Commercial Buildings Energy Consumption Survey[27]. A review of energy profiles in these sources and the historical deployment of CHP in the C&I sectors produced the following target applications:

SIC	Application
451	Airports
581	Restaurants
651	Apartments
701	Hotels & Lodging
721	Commercial Laundries
754	Carwashes
799	Health Clubs
805-6	Health Care
821-2	Education
84	Museums & Zoos

These applications represent over 75% of the existing CHP market in the C&I sectors. All have significant and concurrent electric and thermal loads as shown in Table 2-3.1.

Table 2-3.1 Typical Electric and Thermal Loads for Select Commercial Applications

Application	*Average Electric Demand (W/ sq ft)*	*Electric/Thermal Energy Ratio*
Education	1-2	0.7
Health Care	3-4	0.9
Lodging	2-3	0.9
Food Service	5-6	2.8
Office Buildings	3-5	2.6
Food Sales	8-9	10.6
Apartments	0.7 kW/unit	0.8

26 Petroleum Information / Dwights LLC, *Commercial Energy Profile Database*, November 1998

27 Energy Information Administration , Commercial Buildings Energy Consumption Survey, 1996

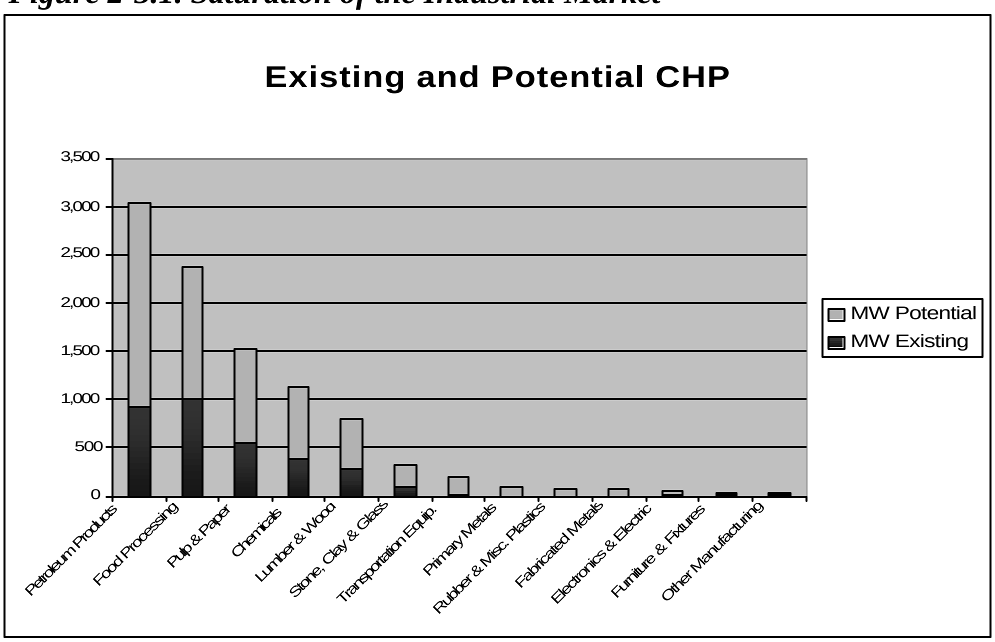
Similar to the methodology used in the industrial sector, the number of C&I establishments contained in specific size categories was estimated using California employment data and electric demand estimates from the data sources identified above. Based on OSEC experience and analysis of existing CHP capacity, a minimum size limit was placed on potential C&I facilities of 50 kW. In addition, potential CHP candidates were limited to C&I facilities with E/T ratios between 0.5 and 3.0. The analysis aggregated the results into the following system size categories for C&I sectors:

- 50kW - 250 kW
- 250 kW - 1 MW
- 1 MW - 5MW
- 5 MW - 20 MW
- > 20 MW

Limitations

Several limitations to the analysis suggest that the resulting estimates of market potential are conservative: there are additional potential CHP applications beyond those selected for analysis in the C&I sector, but data were not readily available to accurately estimate potential in these applications with confidence; all systems were sized to produce only enough cogenerated electricity that could be consumed with-in the plant or facility installation; non-traditional forms of CHP (i.e., shaft power and heat activated cooling loads) were not considered; and the technical potential was estimated only for existing facilities, the potential represented by growth in the industrial and C&I sectors was not included.

Figure 2-3.1. Saturation of the Industrial Market



Industrial Sector Results

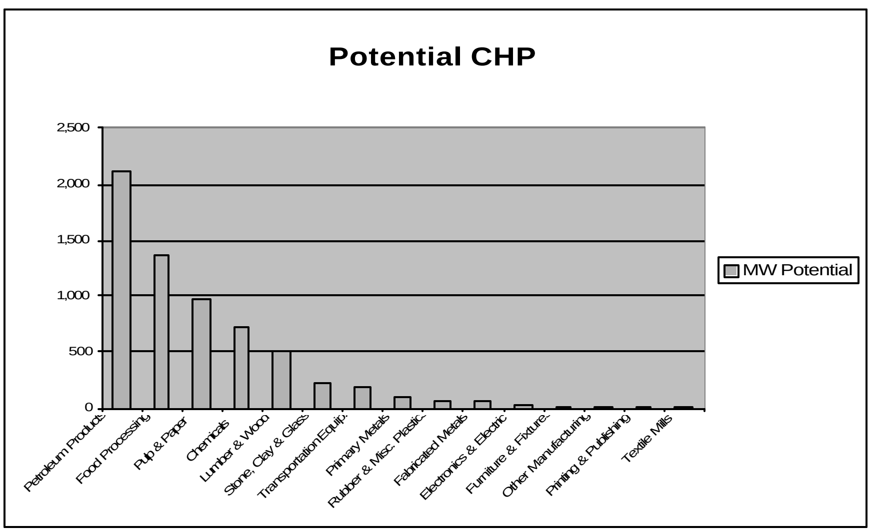
Summary

Following the methodology described above, the technical potential for CHP at existing industrial facilities in California is estimated to be 6506 MW[28]. The technical potential at existing Commercial and Institutional sites is estimated to be 5602[29] MW.

A summary of the technical potential for the industrial market by sector is presented in Figure 2-3.1. The figure also shows the current saturation of each sector. In most cases, the greatest remaining CHP potential lies in those industries that have traditionally used CHP in the past and that have high steam consumption.

Results for the industrial markets are for various size categories in Table 2-3.2. The Petroleum industry represents the largest opportunity for new CHP with over 2100 MW of potential capacity, although it does not have the highest existing installed capacity. As the data will show, much of this potential is contained in a few large sites. Food processing has the highest current saturation of CHP, over 42% of total CHP capacity having been already installed. (Saturation is calculated by dividing existing MW by total installable MW—existing plus potential—for a particular sector.) Food processing also has the second largest opportunity for additional CHP with close to 1400 MW of new capacity possible at existing sites. The potential in food processing is spread across all size categories. The Pulp and Paper, Chemicals and Lumber and Wood industries represent significant CHP opportunities as well, with 978 MW, 726 MW and 505 MW of potential capacity respectively. The remaining industrial markets represent close to 820 MW of potential CHP capacity in total.

Figure 2-3.2. Total Industrial CHP Potential



[28] This represents the total of MIPD MW, which are stated in actual peak MW, and CEC-EDD MW, which are average MW. The authors decided that the consistency in MW types was not worth the degradation of accuracy inherent in converting the latter to peak MW or the former to average MW; the high capacity factor of the industrial sector also narrows or eliminates the gap between the two.

[29] Stated in average MW for all commercial and institutional sectors.

Table 2-3.2 shows a complete breakout of the estimated industrial market potential by SIC, by size category (in MW) with total site counts. Sector breakdowns in terms of size are useful to begin to assess which technologies might apply to various industrial applications.

Table 2-3.2. Industrial Potential Sites and Capacity by Size Category and SIC Code

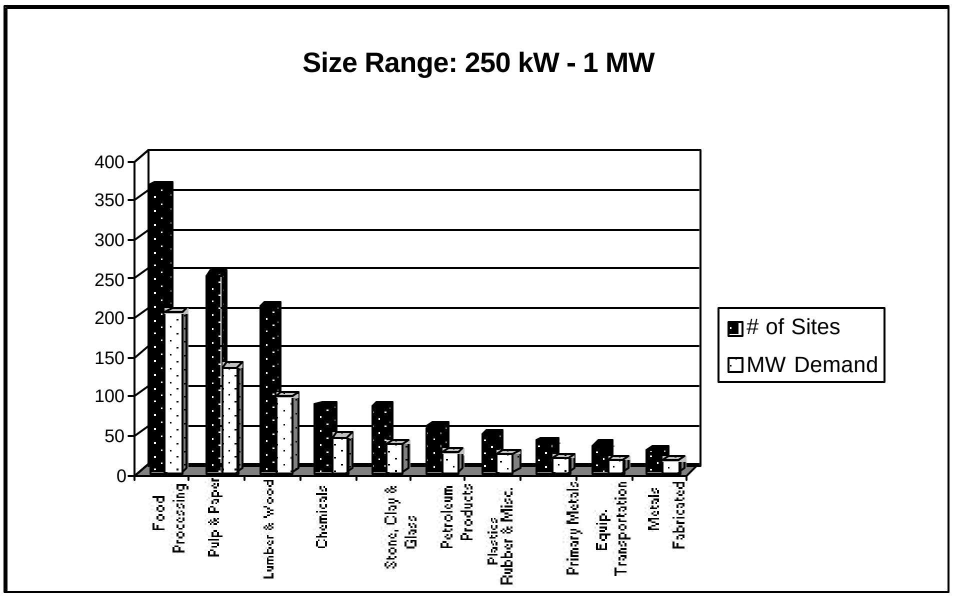
Potential MW & sites		250 kW - 1 MW		1 - 5 MW		5 - 20 MW		> 20 MW < 40 MW		> 40 MW		TOTAL	
Industrial Sector		# of Sites	MW Demand	# of Sites	MW Demand	# of Sties	MW Demand	# of Sties	MW Demand	# of Sites	MW Demand	**# of Sites**	**MW Demand**
20	Food Processing	364	203.1	147	327.1	32	331.8	8	194.8	6	303.2	**557**	**1360.0**
22	Textile Mills	8	3.7	5	11.1	1	0.8	0	0.0	0	0.0	**14**	**15.6**
23	Apparel	4	2.4	1	0.2	0	0.0	0	0.0	0	0.0	**5**	**2.6**
24	Lumber & Wood	211	96.6	37	58.1	12	117.1	2	52.4	3	180.5	**265**	**504.6**
25	Furniture & Fixtures	18	7.4	5	14.5	0	0.0	0	0.0	0	0.0	**23**	**21.9**
26	Pulp & Paper	251	134.3	143	281.1	13	146.6	3	74.9	4	341.3	**414**	**978.2**
27	Printing & Publishing	8	4.6	2	3.2	1	9.3	0	0.0	0	0.0	**11**	**17.0**
28	Chemicals	85	45.2	95	162.8	3	50.3	1	30.6	3	417.4	**187**	**726.3**
29	Petroleum Products	58	25.6	41	86.9	21	208.3	0	0.0	15	1798.2	**135**	**2118.9**
30	Rubber & Misc. Plastics	49	24.2	13	36.5	1	13.7	0	0.0	0	0.0	**63**	**74.4**
31	Leather	1	0.2	2	1.3	0	0.0	0	0.0	0	0.0	**3**	**1.5**
32	Stone, Clay & Glass	83	36.9	22	50.7	1	4.2	0	0.0	1	138.0	**107**	**229.8**
33	Primary Metals	40	18.0	16	33.4	4	26.8	2	26.5	0	0.0	**62**	**104.7**
34	Fabricated Metals	28	15.5	17	35.5	2	18.6	1	2.2	0	0.0	**48**	**71.8**
35	Industrial Machinery	4	2.1	6	9.7	1	3.0	0	0.0	0	0.0	**11**	**14.8**
36	Electronics & Electric	14	7.0	5	11.6	2	21.7	0	0.0	0	0.0	**21**	**40.3**
37	Transportation Equip.	35	16.3	14	28.4	8	94.1	0	0.0	1	53.6	**58**	**192.5**
38	Instruments & Products	6	1.5	2	2.9	2	8.3	0	0.0	0	0.0	**10**	**12.7**
39	Other Manufacturing	13	3.2	9	8.8	0	0.0	1	6.5	0	0.0	**23**	**18.6**
	TOTALS	**1280**	**647.7**	**582**	**1183.8**	**104**	**1054.7**	**18**	**388.0**	**33**	**3232.2**	**2017**	**6506.3**

A series of figures for the five different size categories reveals where the potential lies in the various industrial sectors. For each of the following figures, the top ten sectors have been selected for analysis. A reader who is interested in the other SICs not listed in the chart may consult Table 2-3.1 which contains the source data for the following charts.

Size Range: 250kW to 1 MW

Food Processing leads this size category both in sites and capacity, with just over 200 MW of potential CHP capacity at over 350 sites. (See Figure 2-3.3.) The Food sector is followed by Pulp and Paper, Lumber and Wood, and Chemicals. There are approximately 1280 total sites in this size representing 647 MW of CHP potential.

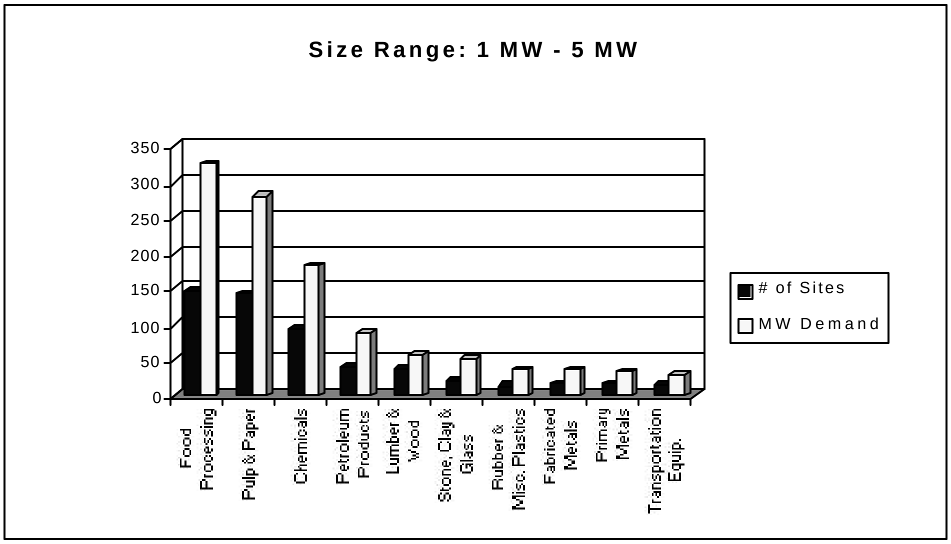
Figure 2-3.3. Potential Industrial CHP between 250 kW and 1 MW



Size Range: 1 MW to 5 MW

Food Processing leads in this category, followed by the Pulp and Paper, Chemicals and Petroleum industries. The distribution is very similar to the previous smaller size category, showing strong potential across all top sectors, with the top three industries dominating. The average site is about 2 MW across all sectors. (See Figure 2-3.4.) There are 582 sites in this category representing approximately 1183 MW of CHP potential.

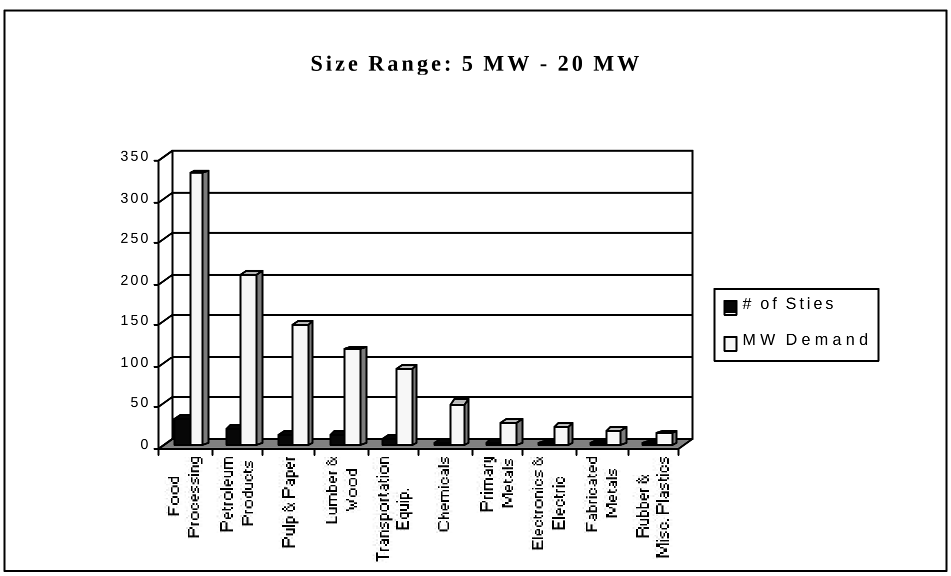
Figure 2-3.4. Potential Industrial CHP between 1 MW and 5 MW



Size Range: 5 MW to 20 MW

Food leads all sectors again in this size category with 32 sites and over 330 MW of potential capacity. The next three industries are Petroleum, Pulp and Paper, and Lumber and Wood. The top six sectors each have over 50 MW of potential. Average MW per site is approximately 10 MW. The total number of sites is 104; the total MW potential is over 1054. (See Figure 2-3.5.)

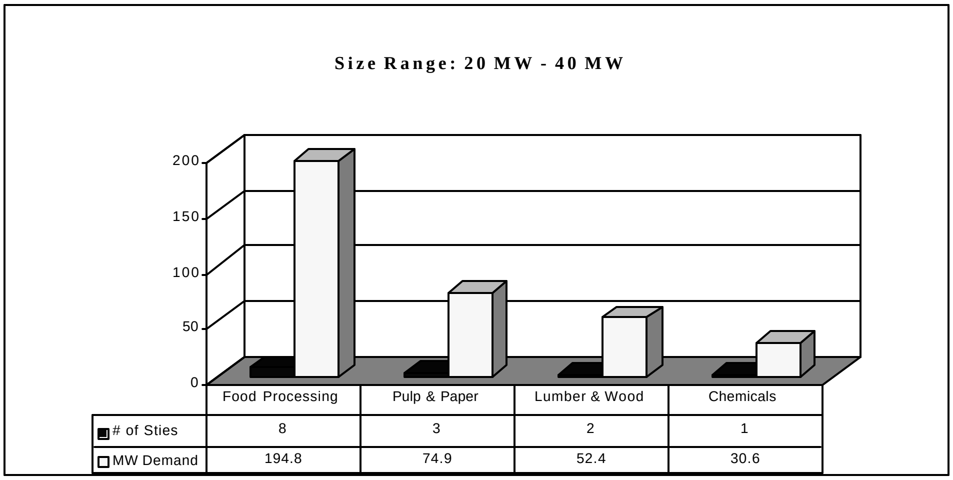
Figure 2-3.5. Potential Industrial CHP between 5 MW and 20 MW



Size Range: 20 MW to 40 MW

Food processing is the leader in this category, followed by Lumber and Wood, Pulp and Paper and Chemicals. Petroleum has no sites in this size range. Average size per site is about 20 MW for Food, with the others averaging 25 to 30 MW. There are a total of 18 sites and 388 MW of CHP potential in this size category.

Figure 2-3.6. Potential Industrial CHP between 20 MW and 40 MW

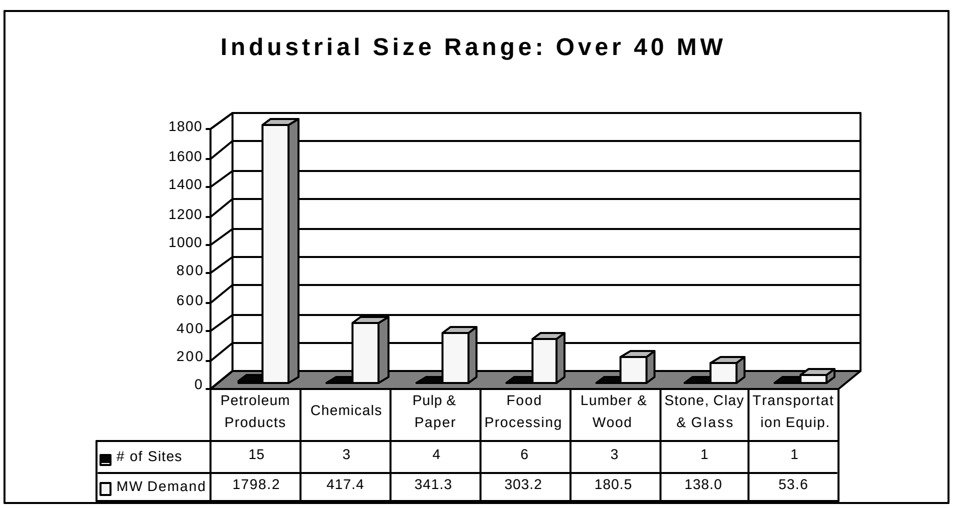


	Food Processing	Pulp & Paper	Lumber & Wood	Chemicals
# of Sties	8	3	2	1
MW Demand	194.8	74.9	52.4	30.6

Size Range: Over 40 MW

This largest size category is dominated by the petroleum sector. Nearly 1800 MW out of 3232 MW and 15 sites out of 33 total sites are represented by petroleum refiners and other petroleum handling sites.

Figure 2-3.7. Potential Industrial CHP Over 40 MW



	Petroleum Products	Chemicals	Pulp & Paper	Food Processing	Lumber & Wood	Stone, Clay & Glass	Transportat ion Equip.
# of Sites	15	3	4	6	3	1	1
MW Demand	1798.2	417.4	341.3	303.2	180.5	138.0	53.6

These 15 facilities comprise over 26% of the total technical potential of the entire industrial sector. An assessment of the market will necessarily pay close attention to these sites and why they did not develop cogeneration earlier under the standard offer contracts of PURPA.

Commercial & Institutional (C&I) Sector Results

Most of the existing CHP activity in California, in terms of MW capacity, took place at the large industrial sites. As shown earlier in Figure 2-2.4, 88% of installed CHP capacity is in the industrial sector, with only 12% in the commercial and institutional sectors combined. At the same time, Figure 2-2.3 shows that the number of existing CHP suites are fairly evenly distributed among the three sectors. Based on this history, average CHP capacity per site can be expected to be less in C&I than in the industrial sector; there will be fewer large sites in C&I; and saturations for most C&I sectors will be much lower.

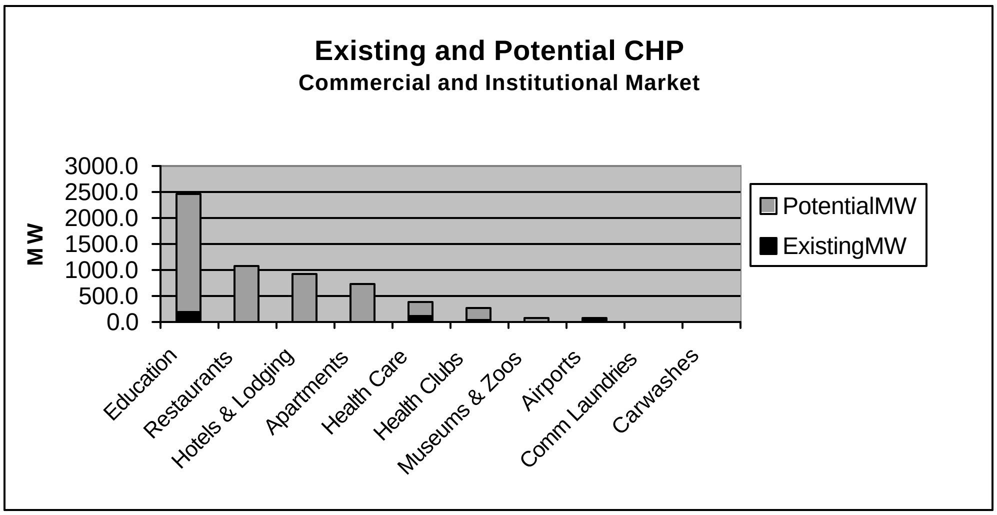
Table 2-3.3 on the following page shows a complete breakout of the estimated C&I market potential by SIC and by size category (in MW) with total site counts. Sector breakdown in terms of size is useful to begin to assess which technologies might apply to various commercial and institutional sectors.

Table 2-3.3. Commercial and Institutional Potential Sites and Capacity by Size Category and SIC Code

		50 - 250 kW		250 kW - 1 MW		1 - 5 MW		5 - 20 MW		> 20 MW		Totals	
. SIC Code	Sector	# of Sites	Demand	# of Sites	Demand	# of Sites	Demand	# of Sties	Demand	# of Sites	Demand	# of Sites	Demand
458	Airports	173	18.58	22	8.17	23	31.50	0	0.00	0	0.00	218	58
581	Restaurants	14,374	1,025.70	48	27.23	22	41.08	0	0.00	0	0.00	14,444	1,094
651	Apartments	3,340	364.22	482	254.13	40	83.69	0	0.00	0	0.00	3,862	702
701	Hotels & Lodging	1,980	210.18	557	322.49	139	308.93	9	61.16	0	0.00	2,685	903
721	Comm Laundries	82	3.84	21	5.25	2	2.00	0	0.00	0	0.00	105	11
754	Carwashes	17	1.72	3	0.75	2	2.00	0	0.00	0	0.00	22	4
799	Health Clubs	723	101.52	46	24.08	36	91.65	0	0.00	0	0.00	805	217
805-6	Health Care	994	113.66	141	53.13	120	117.34	0	0.00	0	0.00	1,255	284
821-2	Education	1,797	254.52	1,290	724.36	144	302.10	58	374.82	14	599.48	3,303	2,255
84	Museums & Zoos	79	11.10	28	18.25	6	12.89	2	10.00	1	20.00	116	72
	TOTALS	**23,559**	**2,105**	**2,638**	**1,438**	**534**	**993**	**69**	**446**	**15**	**619**	**26,815**	**5,602**

The Educational Sector (primary and secondary schools and colleges and universities) has the largest installed base of CHP with over 198 MW; it has the greatest overall technical potential as well, with 2,255 MW[30]. Restaurants, Hotels and Lodging, and Apartments follow with 1094 MW, 902 MW and 702 MW respectively. Of these, Restaurants and Hotels each have less than one MW of CHP currently installed; There are about 15 MW of currently installed CHP capacity in Apartments. The reasons for this disconnect between potential and actual penetration is the result of many factors. Potential industrial sites are about sixteen times larger than the average potential commercial site (208 kW vs 3.2 MW); commercial sites have lower capacity factors, which makes paybacks longer; and there were fewer cost-effective CHP technologies in the smaller capacities in the past.

Figure 2-3.8. Saturation of Commercial & Institutional Market



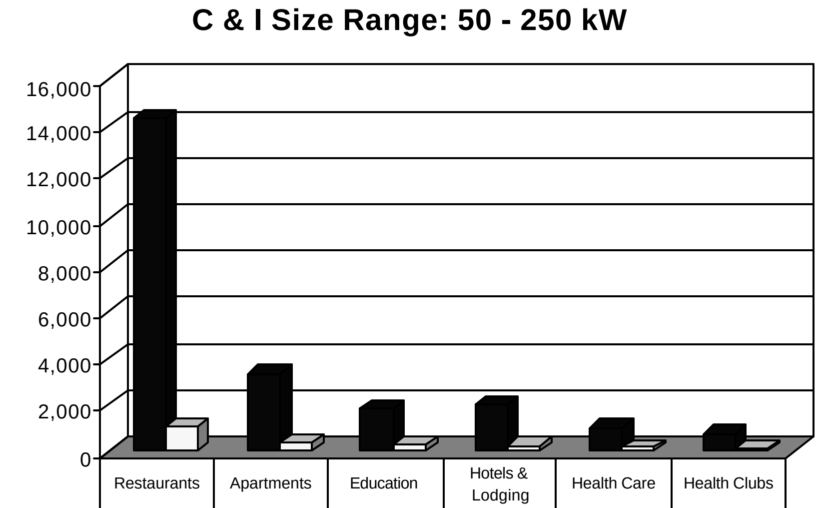
The commercial sector with the highest saturation of existing CHP is Airports, with over 33% of the technical potential already developed. Next is Health Care (hospitals and nursing homes), with over 28% of the technical potential installed. Health and recreation clubs follow with over 20% market saturation. Of these, Health Care has the most remaining potential capacity, with 284 MW. Health clubs have 217 MW and Airports haves 58 MW of CHP potential.

Size Range: 50 to 250 kW

The Restaurant sector leads the smallest C&I size category, 50-250 kW, both in sites and potential capacity. Many of these smaller sites have relatively high E/T ratios and may not be good candidates for CHP when site specific requirements such as concurrent electric and thermal loads are considered. Average system size for this category is 70 kW.

[30] The educational sector also has the lowest capacity factor in C&I, at 21%; this will be an obstacle to turning this potential into actual installations.

Figure 2-3.9. Potential C&I CHP between 50 kW and 250 kW

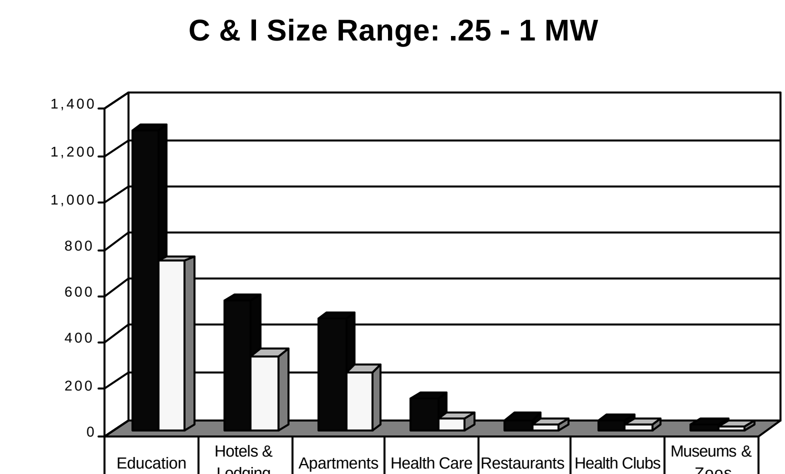


	Restaurants	Apartments	Education	Hotels & Lodging	Health Care	Health Clubs
# of Sites	14,374	3,340	1,797	1,980	994	723
Demand	1,025.7	364.2	254.5	210.2	113.7	101.5

Size Range: 250 kW to 1 MW

Educational facilities lead the 250 kW to 1 MW size category, with 1290 sites and 724 MW of potential CHP capacity. Hotels, Apartments and Health Care facilities follow. Restaurants drop to fifth, an indication that the sector is concentrated in the smallest size (almost 94% of restaurants consume fewer than 250kW). Each of the top three market sectors in this size category average over 500 kW per site.

Figure 2-3.10. Potential C&I CHP between 250 kW and 1 MW

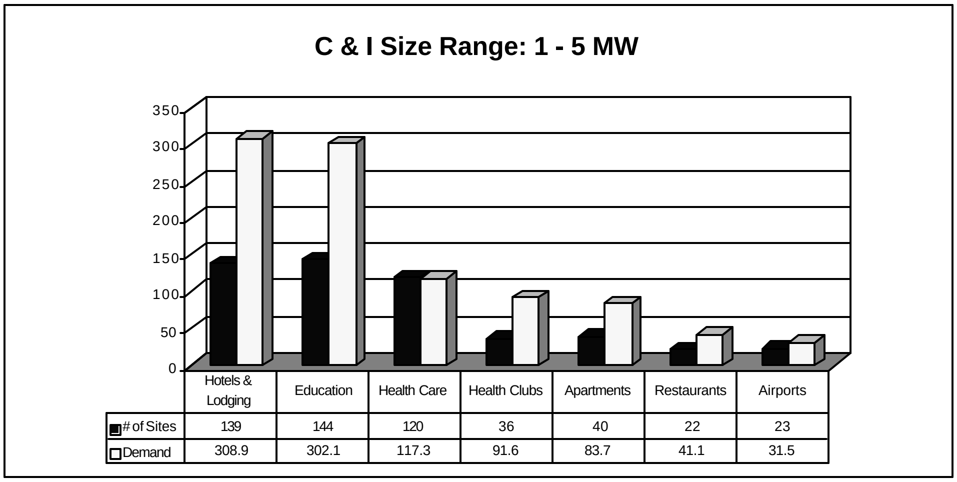


	Education	Hotels & Lodging	Apartments	Health Care	Restaurants	Health Clubs	Museums & Zoos
# of Sites	1,290	557	482	141	48	46	28
Demand	724.4	322.5	254.1	53.1	27.2	24.1	18.3

Size Range: 1 MW to 5 MW

Hotels & Lodging and Education lead the one to five MW size category, followed by Health Care, Health Clubs, and Apartments. Sites average a little over 2 MW for most sectors in this size, with the exception of Health Care facilities, which average 1 MW per site.

Figure 2-3.11. Potential C&I CHP between 1 MW and 5 MW

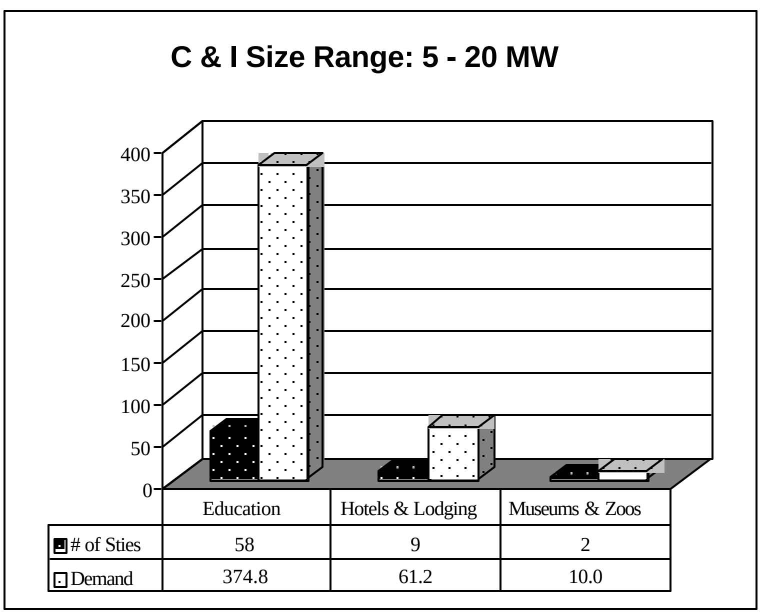


	Hotels & Lodging	Education	Health Care	Health Clubs	Apartments	Restaurants	Airports
# of Sites	139	144	120	36	40	22	23
Demand	308.9	302.1	117.3	91.6	83.7	41.1	31.5

Size Ranges: 5 MW to 20 MW; and 20+ MW

Education dominates the larger size ranges, with 58 sites in the 5-20 MW range and 14 sites larger than 20 MW. At these size ranges, the sites are mostly colleges and universities. Average capacity is about 6.5 MW for both Education and Health facilities in the 5 to 20 MW range.

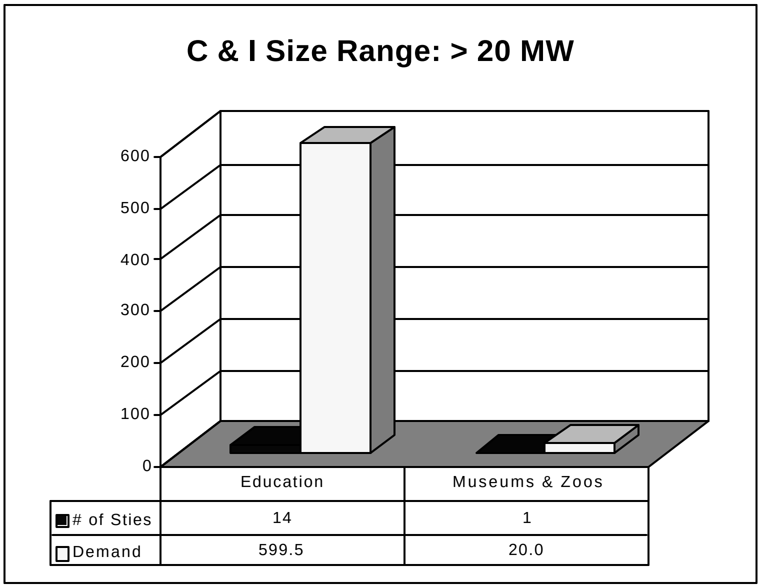
Figure 2-3.12. Potential C&I CHP between 5 and 20 MW



	Education	Hotels & Lodging	Museums & Zoos
# of Sties	58	9	2
Demand	374.8	61.2	10.0

The average for Educational sites >20MW is 42 MW. The Museum/Zoo sector numbers are minimum estimates that had to be made because of confidentiality issues. Each of the two sites is given the minimum of the size category, 5 MW; these facilities could be as large as 20 MW.. The single site in the >20 MW category of this same sector is also a minimum estimate that could be of greater size.

Figure 2-3.13. Potential C&I CHP Over 20 MW



In summary, CHP potential in C&I is led by the educational sector, which shows consistent potential across all size categories and is virtually the only sector in C&I with facilities over 5 MW in size. It will be necessary to keep in mind the low capacity factor of this sector, especially in primary and secondary schools, in turning this potential into actual installations. The Restaurant sector will become more attractive as smaller technologies become more cost effective. Hospitals and Hotels both show significant potential in the mid-range sizes between 500kW and 1.5 MW.

3.0 Market Assessment for Combined Heat and Power

Introduction

This section provides an assessment of CHP market penetration for California based on the technology cost and performance parameters described in Section 1.0: CHP Technologies and the total market potential for CHP described in Section 2.0: Market Potential.

The market penetration estimates are based on the economic competitiveness of CHP in different size and load applications, the historical market penetration for CHP by size and application, and an evaluation of the impacts of emerging technology and market trends. This section is organized in the following subsections:

- ❑ Electricity and Fuel Price Trends – a presentation of the expected future prices for electricity and natural gas.
- ❑ CHP Economics – an evaluation of CHP technology cost and performance and expected savings and paybacks by size and application.
- ❑ Market Penetration Scenarios – a summary of the market potential described in Section 2 and alternative penetration estimates based on the CHP paybacks for each application and size category and other factors.

3.1 Electricity and Fuel Price Trends

The most significant variables determining future CHP market penetration rates are the expected future retail electricity and gas prices. The market restructuring in the electric industry that is now underway shapes the expected value of these future energy prices. The historical energy prices and base-case forecasts used for this assessment were provided by the California Energy Commission.[31,32]

Because CHP economics are sensitive to the specific retail rate structures, that is the allocation of costs to demand and energy charges and time-of-use rates, we evaluated the current tariff sheets for medium and large customers for Pacific Gas & Electric Company (PG&E) and for Southern California Edison (SCE). Standby tariffs were also examined.

Electric Rates

The California electric industry is currently in the middle of a legislated, multiyear transition to a more competitive market. When the transition is completed, power generation will be a competitive business while transmission and distribution functions will remain a regulated utility

[31] Arikawa, Ben, Revised 1997 Retail Electricity Price Forecast, CEC Draft Report, March 1998
[32] Tomashefsky, Thomas, *et al*., Natural Gas Market Outlook, CEC P300-98-006, June 1998.

monopoly with performance based incentives for efficient operation. The purpose of the transition period is to allow the investor owned utilities (IOU) to divest their generating assets and to recover rate-base costs associated with these assets that are above their market value. The recovery of these above-market costs is being made with a *competitive transition charge* (CTC) applied to all customer rates. The CTC will phase out on or before March 31, 2002. A much-reduced CTC will continue beyond this point to pay for the rate reduction bonds and to cover above market contract payments to qualifying facilities (non-utility generators with utility sales contracts.) The restructuring legislation applies only to IOUs, but municipal utilities are making similar steps so that competition will be instituted statewide.

Historical Rates

The historical price trends for electricity show some of the reasons behind the need for restructuring. Expensive construction programs in the 1970s and 1980s led to a sharp run-up on rates. The non-utility generation (NUG) market that emerged during this period set the competitive price below the utility rate-base price. Large industrial customers with competitive supply options and realistic CHP potential were able to force their regulated rates down to the competitive levels while smaller customers had to pay a larger share of the higher costs. Figure 3-1.1 shows the historical average commercial and industrial electric rates for California in nominal dollars. Industrial rates peaked in 1985 and have been flat or declining ever since. Commercial rates also have turned down in the last few years as competitive pressures have increased.

CEC Forecast

The CEC electricity price forecast is shown in Figure 3-1.2 along with the historical data in inflation adjusted real dollars. First, the use of real dollars shows that electricity rates have been declining for both commercial and industrial customers since the early 1980s. A sharp drop in rates is forecast when the CTC for generation assets expires at the end of 2001 or shortly thereafter. This drop is then followed by a forecast of very stable but slightly declining real rates through the end of the forecast period in 2017. The CEC forecast shows the average real commercial rate after restructuring at 6.15 ¢/kWh and the average industrial rate at 4.77 ¢/kWh.

It is interesting to compare these forecast competitive prices with the commercial and industrial rates in 1997 (10.21 and 7.11 ¢/kWh) and the all-time peak real rates in 1986 (12.51 and 10.62 ¢/kWh respectively.) It is clear that the prevailing rates against which CHP must compete over the forecast period will be much lower than they are now and less than half what they were during the peak years of CHP market expansion.

Figure 3-1.1 Historical Commercial and Industrial Electric Prices in California (nominal $/kWh)

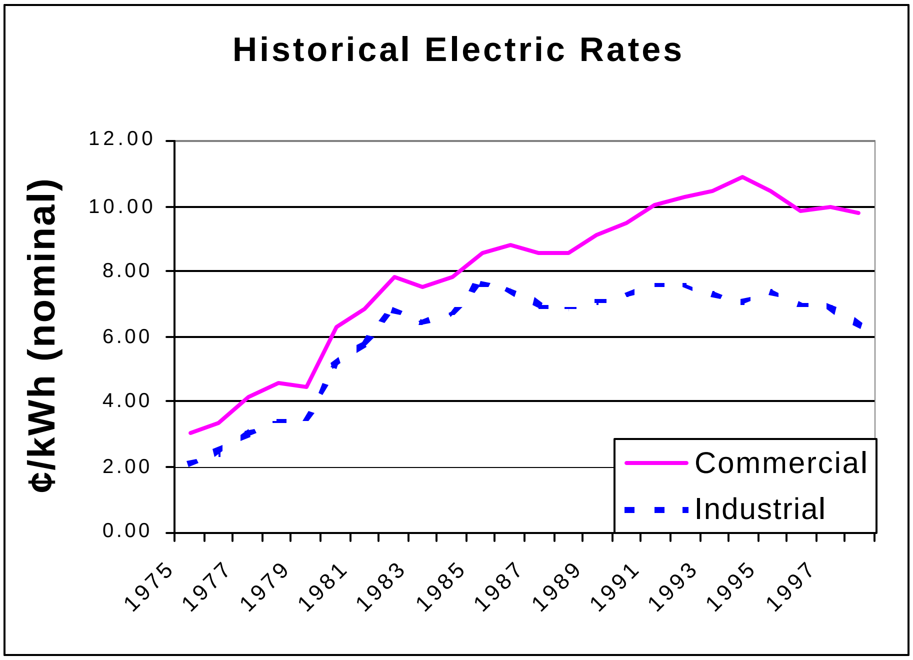
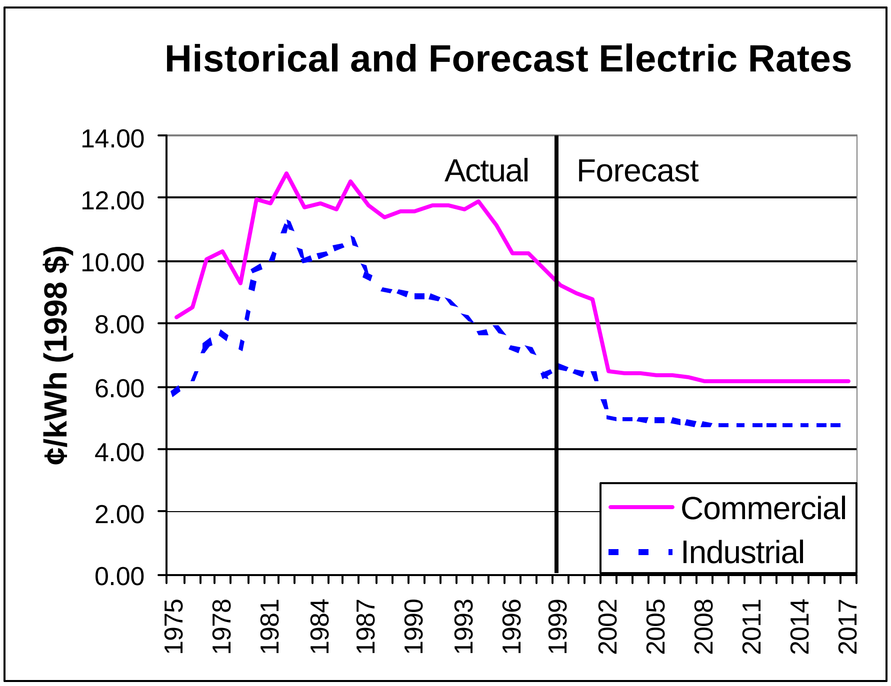


Figure 3-1.2. Historical and Forecast Commercial and Industrial Electric Prices in California (real $/kWh)

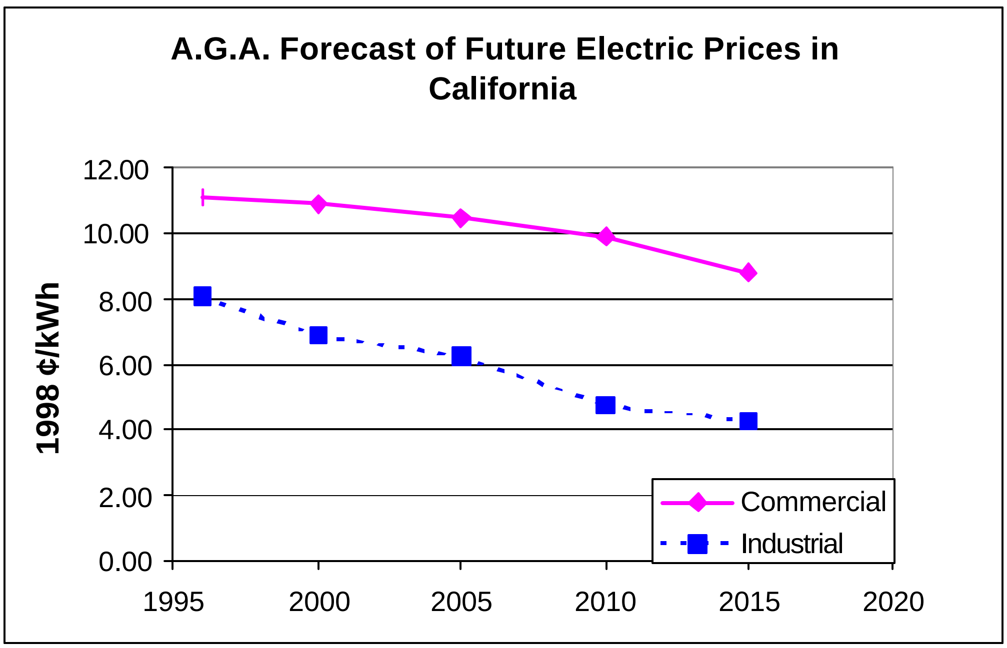


American Gas Association Electricity Price Forecast

The American Gas Association sponsored a study of the impact of electric industry restructuring on future electricity prices.[33] The forecast covers the period between 1996 and 2015. The results of their California analysis for commercial and industrial rates are shown in Figure 3-1.3. The source numbers were presented in $1996 dollars without sales and excise taxes. In Figure 3-1.3, these numbers have been adjusted upwards by 15.7% to account for the addition of taxes and inflation from 1996 to 1998 base year dollars.

The A.G.A. analysis shows a very similar level of cost reduction for the industrial sector, but a much lower reduction in rates for the commercial sector. In addition, the A.G.A. forecast does not show the rapid transition impact that will occur as a result of the early phase-out of the CTC. This forecast has been included for reference purposes only. After reviewing the CEC and the A.G.A. forecasts, the CEC forecast was selected for this analysis.

Figure 3-1.3. American Gas Association Forecast of Future Electric Prices (adjusted to $1998/kWh with taxes added)



[33] Chernoff, Harry, et al., The Impact of Industry Restructuring on Electricity Prices, July 1998., American Gas Association Report #F60198, July 1998.

Electric Tariff Structure – Fixed versus Variable Charges

The average projected sector prices for electricity provide a gross indication of the level of competition for CHP projects. However, the actual tariff structures will have a strong impact on the competitiveness of a particular CHP project. The relevant tariff components are

- Demand charges that are currently differentiated into a number of categories with a 5-month summer period and a 7-month winter period defined.
- Energy charges that can vary by season and by time-of-use
- Standby charges for customers with their own generation.

Current PG&E and SCE tariffs were used to provide a basis for developing a simplified CHP economic competitiveness model. The tariffs analyzed are as follows:

Southern California Edison

- GS-2 General Service – for customers below 500 kW demand
- TOU-8 Time-of-Use General Service – for customers above 500 kW demand
- Schedule S Standby – for customers with QF power production that use the utility for supplemental, maintenance, or emergency purposes.

Pacific Gas & Electric

- Schedule A-10 – Medium General Demand-Metered Service – for customers using at least 50,000 kWh/yr with demand less than 500 kW
- Schedule S Standby Service

These tariff sheets are included in Appendix A of this report.

The SCE GS-2 Tariff summarized in Table 3-1.1 applies to nonresidential customers with demand meters whose peak load is between 20-500 kW. There is a nominal customer charge of $60.30 per month regardless of demand or energy use. There is a two-part demand charge. The *Facilities Related Component* of $5.40/kW is applied to maximum demand each month. There is an additional *Time Related Component* of $7.75/kW that is also charge on maximum monthly demand during the defined summer period of June through October. The customer pays an energy charge of $0.07692/kWh on the first 300 hours *times* the peak demand for that month. In other words, since there are 730 hours in the average month, all consumption that equals only 300 hours of use or less, i.e. a 41% load factor, are charged at this block 1 rate. Only customers, with a load factor higher than 41% would have any energy use that would fall above this 300-hour block. The energy rate for second block is much lower at $0.04391.

Table 3-1.1 SCE GS-2 Tariff

SCE GS-2	
Customer Charge	$60.30
Demand Charges	
Facilities Demand	$5.40
Additional Summer Peak Demand	$7.75
Energy Charges	
Block 1 (300 X Peak Demand.)	$0.07692
Block 2 (all above Block 1)	$0.04391

Summer Period begins June 1 and ends October 31

In the customer economics calculation model presented in the next section, we defined specific customer loads to reflect the various market segments. Table 3-1.2 shows the average electricity costs for a typical large commercial customer on SCE GS-2. This customer has a load factor of 38.8% with a peak demand of 400 kW and a minimum demand of 125 kW. A specific summer peaking load pattern was assumed. Typically, health care, lodging, and food service applications have a load factor at or above this range. High energy-intensity offices and public buildings also approach this range but average 30% or less. The average rate for this typical customer is nearly 10 ¢/kWh based on the rate sheet, or about 11 ¢/kWh with taxes. The share of this customer's annual bill that goes to each type of charge is calculated – 73% goes to the energy charge, 27% goes to the demand charge, and the customer charge is an insignificant portion of the bill.

Table 3-1.2. Average Cost for Selected Customer on SCE GS-2

Example Customer Profile on GS-2	
Peak Demand	400 kW
Minimum Demand	125 kW
Annual Load Factor	38.8%
Average Rate	$0.0992/kWh
Average Rate w Taxes	$0.1092/kWh
Share of total Bill	
Customer Charge	0.54%
Demand Charges	26.56%
Energy Charges	72.91%

We also examined the rates for larger commercial and industrial customers under SCE TOU-8. This rate category is applicable to most customers with monthly demands above 500 kW. Table 3-1.3 shows the customer charge plus time and season dependent demand and energy charges. The table shows the charges for a customer receiving service at the highest voltage levels. Somewhat higher rates apply to customers receiving service at lower voltages. Time-related peak demand rates are \$16.15/kW and peak energy rates are very high. However, the peak period applies to only 630 hours during the year or slightly more than 7% of the total hours in the year.

Table 3-1.3. SCE TOU-8 Tariff

SCE TOU-8 (voltages above 50kV		
Customer Charge	\$349	
Demand Charges	Summer	Winter
Facilities Demand	\$0.65	\$0.65
Time Related, Peak	\$16.15	\$0.00
Time Related, Mid-peak	\$2.45	\$0.00
Energy Charges		
Peak	\$0.07397	n/a
Mid Peak	\$0.05053	\$0.06093
Off-peak	\$0.03755	\$0.03872

Summer Months: June through October
Peak Hours: Weekdays Noon to 6pm
Mid Peak: Weekdays 9am to noon, 6pm to 11pm summers; 9am to 9pm winters
Off-peak: All other times including 8 holidays

We defined an example customer load to provide a basis for the economic analysis for larger customers under this rate as shown in Table 3-1.4. This customer would be an industrial customer with 4,000 kW of peak demand and 2,250 kW of minimum demand. This customer is 10 times larger than the customer in the GS-2 example and has a much higher annual load factor of 64.9% consistent with a multi-shift industrial operation. The average power cost for this customer is \$0.0663/kWh based on the tariff or \$.0729/kWh with taxes added in. About 1/4th of the total costs come from the demand charges and 3/4^{ths}come from energy charges.

Table 3-1.4. Average Cost for Selected Customer on SCE TOU-8

Example Customer Profile	
Peak Demand	4000 kW
Minimum Demand	2250 kW
Annual Load Factor	64.9%
Average Rate	$0.0663 /kWh
Average Rate w Taxes	$0.0729 /kWh
Share of total Bill	
Customer Charge	0.28%
Demand Charges	24.81%
Energy Charges	74.91%

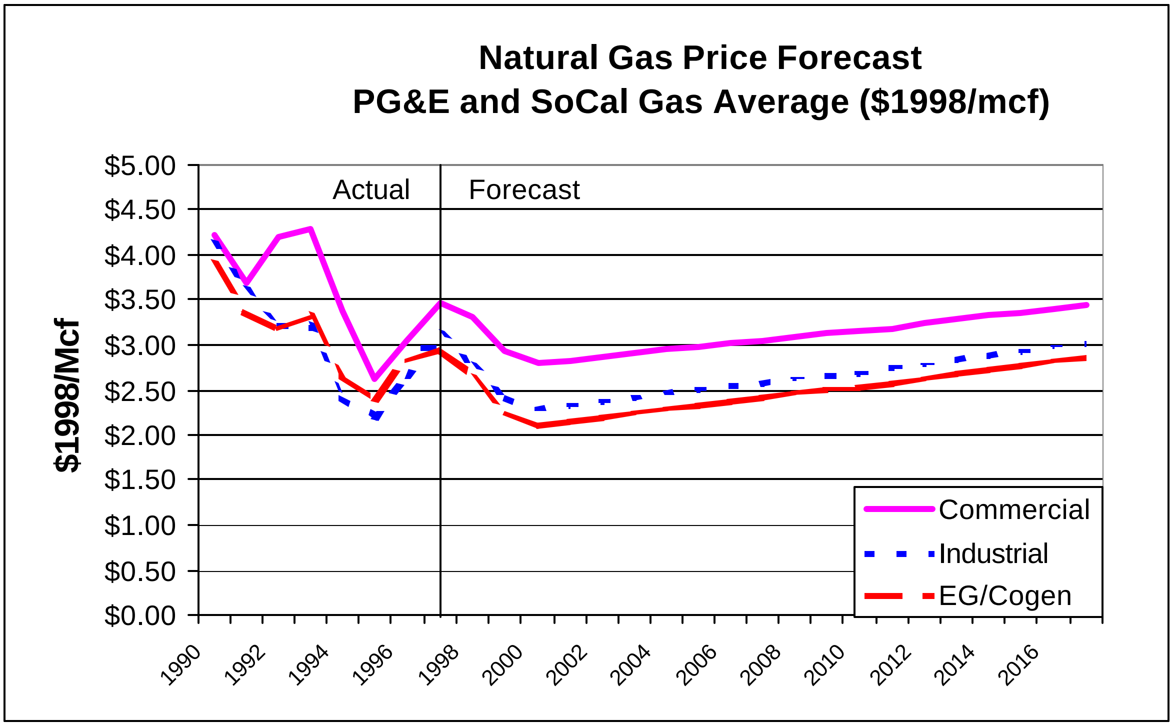
Both SCE and PG&E have standby rates that apply to customers "taking service under a regular service rates schedule and where a part or all of the electrical requirements of the customer can be supplied from a cogeneration or small power production source which meets the (QF definition under PURPA)."[34] Essentially, the standby charge is equal to the facilities related component of the demand charge times the contracted level of standby demand – generally equal to the generator capacity or the facility load whichever is smaller. After a 6-month trial period, the standby customer does not have to pay this demand charge for demand created by scheduled maintenance for the generator so long as there is advance notice and approval by the utility. For all supplementary consumption, the customer continues to receive service under his existing tariff. Customers who operate a "microcogeneration facility" of less than 1-MW and who also are in full compliance with Best Available Control Technology (BACT) are exempt from paying standby charges through June 30, 2000.

Gas Price Forecast

Natural Gas is the predominant fuel used for CHP. We are using forecast natural gas prices as the basis for determining operating costs for CHP. Figure 3-1.4 shows the average PG&E and Southern California Gas Company (SCG) price by sector forecast to 2017. The figure shows the commercial, industrial, and electricity generation/cogeneration gas rates. The industrial and EG/cogen rates are forecast to decline to between $2.12 and $2.29/mcf then gradually rising during the forecast period, but staying below $3.00/mcf.

[34] Southern California Edison Company, *Schedule S*, Tariff effective June 14, 1998.

Figure 3-1.4. CEC Natural Gas Retail Price Forecast ($1998/mcf)



3.2 CHP Economics

In this section we evaluate the competitive position of CHP in terms of future electric and gas prices, CHP technology cost and performance, and typical demand patterns of customers by size and application.

Converting Future Average Electric Prices into Demand and Energy Rates

The forecast electric rates used for this analysis are in the form of average prices. These average rates are assumed to be derived from a three-part rate structure and the average customer load profiles. Because CHP significantly alters a customer's load profile, we felt it was important to convert the average price forecast into a three part rate structure. Typically, what remains after a continuous CHP system is installed at a customer site is a higher average cost of power due to a lower average load factor for the residual. This lower load factor demand yields a higher average price under a three-part rate structure.

we developed an algorithm to convert the average rates into a two part rate structure that would exactly equal the average rate for that selected customer profile. Starting with the current rate structures, we assumed that the off-peak rates, already quite low, would remain the same during the forecast period. For the industrial customer on TOU-8, we assumed that the time related component of demand and the peak and mid-peak would be varied to achieve the forecast average price. For the energy rates we assumed that the difference between the peak rate and the off peak rate would be reduced by same factor as the time-related demand charge reduction. In this way, no matter how low the factor becomes to equal the lowest average price in the forecast, the peak rates never fall below the off-peak rates. For the commercial customer on GS-2, we assumed that both the time-related and the facilities-related components of the demand charge would vary by the same factor required to equal the average price. The difference between the Block 1 and Block 2 energy rates was also reduced by the same factor. In this way, we calculated the yearly factors for both commercial and industrial rates that would provide a two-part rate that would exactly equal the forecast average price for that specific customer load pattern. These factors were calculated for every year of the forecast period for both the commercial and industrial examples so that the economic analysis could be undertaken using the adjusted demand and energy rates. The calculation for the TOU rate is shown below:

Current Peak Energy Rate = P_p
Peak Energy Rate Year n = $P_{op} + (P_p - P_{op}) \times AF_n$
Current Peak Demand Charge = PD_p
Peak Demand Charge Year n = $PD_p \times AF_n$
P_p = current peak energy rate
P_{op} = current offpeak energy rate
PD_p = current peak demand charge
AF_n = adjustment factor in year n that equates the energy bill without CHP using the average rate and the three part energy rates for the customer loads selected for the CHP comparison

Customer Charge, offpeak rate, and facilities demand charge remain the same for all time periods. The adjustment for midpeak demand and energy charges is the same as is shown.

CHP Technology Cost and Performance Characteristics

In the first phase of the overall analysis we evaluated CHP technology cost and performance characteristics in general terms. For this analysis we selected a number of technology profiles that would apply to the various size categories of potential CHP demand. Table 3-2.1 shows these profiles for application sizes that range from as small as 50 kW to 25 MW. The heat rates and recoverable thermal energy factors are based on commercial product specifications — with the exception of the microturbine for which performance factors are estimated based on a composite of development goals from Allied Signal, Capstone, Northern Research. The microturbine cost factors were estimated based on our assessment of early market entry economics and not on the manufacturers projections for high volume production. Their lower cost projections, though not used for the base case, were used as part of a high market penetration scenario to be described in a later section.

Package costs, heat recovery equipment costs, and balance of plant costs can vary widely by application and the degree of competition. We selected the costs in the table to reflect realistic study-estimates for costs for these technologies.

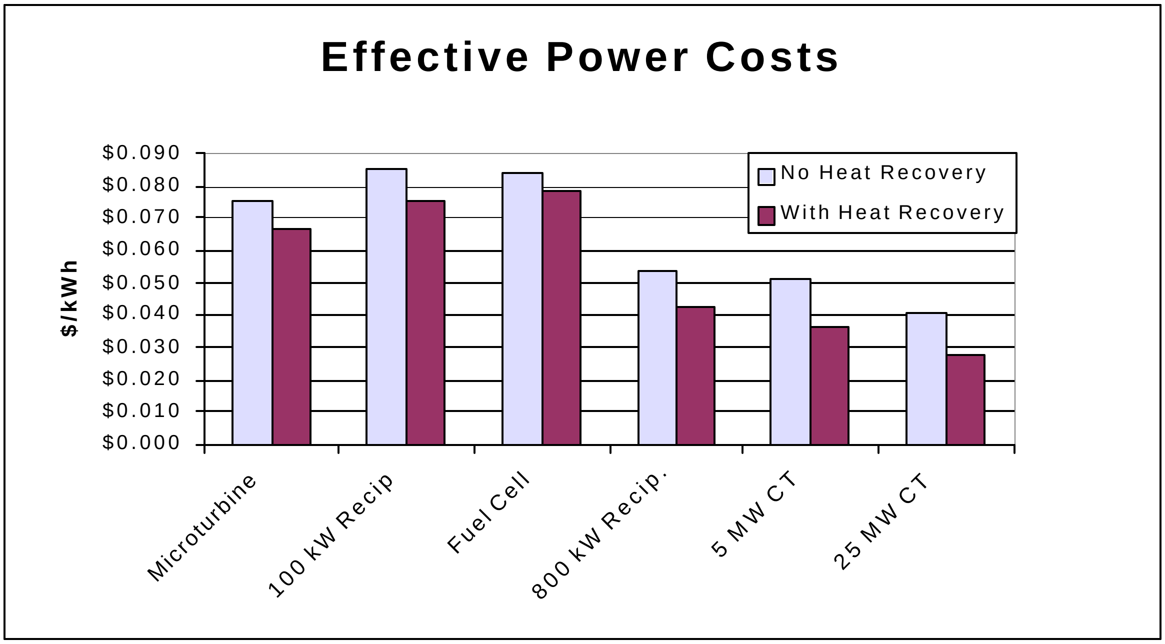
The fuel cell is shown for comparison purposes only. It was not used as one of the representative technologies in the economic analysis.

Figure 3-2.1 shows the effective average power costs achievable by base-load operation of these technologies at these costs for both power only and CHP applications. The small engine and microturbine technologies are assumed to have an economic life of 10 years; all the rest are assumed to have an economic life of 15 years. The CHP costs differ from the power-only costs by the addition of the heat recovery capital costs and the assumption that the heat recovered replaces that produced by an 80% efficient gas-fired boiler. The gas cost for the analysis was assumed to be $2.50/mmBtu.

Table 3-2.1. CHP Technology Cost and Performance Estimates

Representative Onsite Generation Cost and Performance						
	Microturbine	Gas Engine	Fuel Cell	Gas Engine	Gas Turbine	Gas Turbine
Perfromance						
Size kW	50	100	200	800	5,000	25,000
Heat Rate (Btu/kWh HHV)	13,306	13,127	7,584	10,605	11,779	10,311
Recov. Exhaust Heat (Btu/kWh)	4498	1786		1443	5193	4522
Recov. from Coolant (Btu/kWh)		3404	3000	2750		
Cost						
Package Cost ($/kW)	$500	$650	$2,000	$350	$400	$300
Heat Recovery	$150	$100	$75	$75	$75	$75
Emission Controls	$0	$70	$0	$29	$102	$100
Project management	$25	$33	$100	$18	$20	$15
Site & Construction Management	$35	$46	$140	$25	$28	$21
Engineeering	$20	$26	$26	$14	$16	$12
Civil	$50	$75	$100	$38	$15	$13
Labor/Installation	$100	$130	$120	$44	$60	$45
CEMS	$0	$0	$0	$0	$30	$20
Fuel Supply-compressor	$40	$0	$0	$0	$20	$15
Interconnect/Switchgear	$150	$150	$75	$63	$20	$6
Contingency	$25	$33	$60	$18	$20	$15
General Contractor Markup	$164	$197	$270	$101	$81	$64
Bonding/Performance Guarantee	$33	$39	$27	$20	$24	$19
Carry Charges during Constr.	$83	$99	$192	$51	$87	$69
Basic Turnkey Cost ($/kW)	$1,375	$1,647	$3,184	$842	$998	$789
O&M Cost $/kWh	$0.010	$0.014	$0.005	$0.011	$0.003	$0.003

Figure 3-2.1 Example Generated Power Cost Levels for CHP Technologies for Baseload Applications



Application Profiles

Specific application profiles were created for a range of sizes to identify the economic competitiveness as a function of size and application. For example, the commercial customer profile shown in Section 1 was used to create a 150 kW commercial application using multiple microturbines. The industrial customer profile shown in Section 1 was used to create a 2,250 kW industrial application using multiple industrial gas engines. Two larger applications were defined based on gas turbine technology for industrial applications. The technology/application cases used for the economic analysis are as follows:

- ❑ 150 kW commercial application using multiple microturbines
- ❑ 2250 kW industrial application using three gas engines
- ❑ 10 MW industrial application using two gas turbines
- ❑ 50 MW industrial application using two gas turbines

CHP Economic Performance over the Forecast Period

Energy customers use a variety of methods to determine if a particular investment is economically desirable for them. A rule-of-thumb method that is often used for preliminary evaluation of potential projects is the speed with which the initial investment is recovered by the annual savings. This simple payback analysis is calculated by dividing the first year's savings into the initial capital cost providing an estimate of the number of years that will be required to return the initial investment. Many customers will not accept an investment in energy technologies unless it has a payback of 2-3 years or less. Customers may use this restrictive cut-off as a means of allowing for risk that the future savings will not be realized or because they have limited investment funds and are unwilling or limited in their ability to borrow to finance profitable projects. CHP projects generally are financed with a mixture of internal funds and debt financing. Sometimes complicated leasing arrangements are developed that eliminate the need for the site customer to come up with initial investment funds for the project – relying instead on third parties to own the system and take a portion of the benefits. For these types of projects it is common for some kind of discounted cash flow analysis to be conducted by the parties involved in the deal. Net present value (NPV) or internal rate of return (IRR) is calculated to determine if a project is economic. If the NPV is positive or if the IRR is greater than the customer's cost of money, then the project is considered to be economic. Here again, customers may protect themselves from risk by setting high hurdle rates for this type of analysis. For this analysis, we based the customer's acceptance of CHP on the project IRR. We used a "myopic" IRR in that we assumed that the customer valued his yearly savings based on the energy rates prevailing when the investment decision is made rather than based on perfect knowledge of all future prices. Any project with an IRR above 10% would provide customers with economic benefits, but acceptance levels would drop off as the IRR declines to the economic floor. We also calculated simple paybacks for comparison purposes, though these were not used in the market acceptance calculations.

The assumptions for the base analysis are as follows:

- The 150 kW system is on the current SCE GS-2 rate and is assumed to be exempt from standby charges. All other cases are on the current SCE TOU-8 rate, but at the highest voltage level where standby costs are only $0.65/kW. No CTC charges are considered for this comparison as they effectively eliminate any benefit for installing a new CHP system during the transition period.
- The 150 kW system is amortized over 10 years; all of the others are amortized over 15 years.
- The 150 kW system has an annual load factor of 70% due to the greater variability in commercial sector demands. The larger systems are sized to operate at 90% load factor.
- Economic use of recoverable waste heat equals 60% for the 150 kW system commercial sector system and 90% for all industrial systems.
- All system downtime is assumed to occur during off-peak hours, a simplifying assumption that maximizes the economic value of the CHP system.
- Both the CHP fuel cost and the avoided boiler costs are assumed to be $2.50/mmBtu.

The base case results are shown in Table 3-2.2. The paybacks range from 3.7 years (24% IRR) for the small commercial system to 2.2 years (46.5% IRR) for a 50 MW gas turbine plant. Gas engine efficiencies in the intermediate 2,250 kW size show a somewhat faster payback (2.7 versus 2.8 years) due to higher generation efficiencies for the industrial gas engine compared to a small gas turbine. The high quality steam available from a turbine system is probably much more useful to an industrial facility than the combination of hot water and high temperature exhaust available from a gas engine.

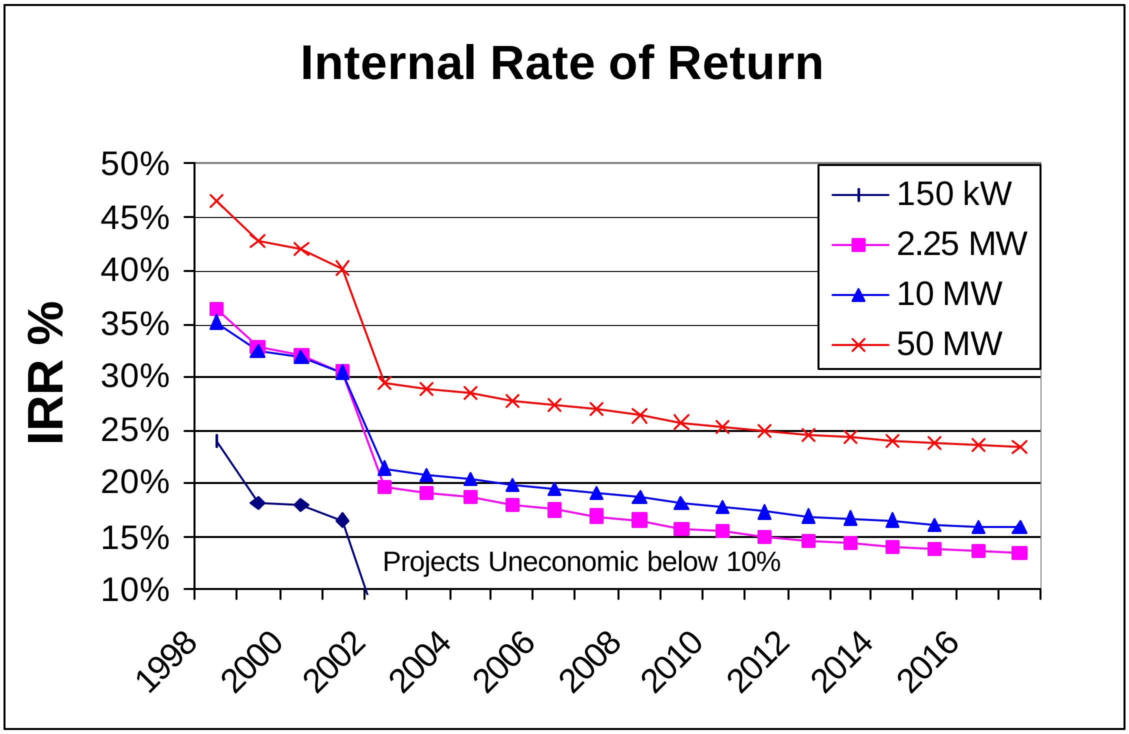
Table 3-2.2. Base Case IRR and Paybacks for CHP Applications

CHP Size Technology	150 kW microturbine	2.25 MW gas engine	10 MW gas turbine	50 MW gas turbine
CHP O&M Cost	$9,194	$173,448	$210,240	$1,051,200
CHP Fuel	$30,585	$418,049	$2,063,661	$9,032,533
Thermal Savings	-$7,754	-$185,949	-$909,830	-$3,961,211
Utility Bill	$60,178	$560,055	$3,392,197	$16,942,558
Total Costs w CHP	$92,203	$965,603	$4,756,268	$23,065,081
Base Utility Bill	$148,234	$1,658,687	$8,275,010	$41,356,624
Annual Savings	$56,031	$693,085	$3,518,742	$18,291,543
First Cost	$206,219	$1,895,521	$9,982,149	$39,470,358
Payback Years	3.68	2.73	2.84	2.16
IRR	24.01%	36.31%	35.15%	46.52%

These base-case payback and IRR calculations were then adjusted based on the year-by-year electricity and gas price forecasts according to the methodology described in the beginning of this section. The generation gas price forecast was used for the gas price for both the generation fuel and the avoided boiler costs—somewhat understating the benefits of heat recovery which can displace fuel use at the higher commercial and industrial rates.

The year-by-year IRRs for the four technology/application cases are shown in Figure 3-2.2. In the current high price environment, the IRRs for the systems are all very economically attractive – IRRs of 35-46% for the industrial systems and 24% for the 150 kW commercial system. Again, these numbers are not useful for determining market penetration in the transition years because of the application of the nonbypassable departing load charges designed to ensure that all customers pay their fair share of transition costs. After the transition period is over, CHP project returns decrease due to the much lower forecast electricity rates. As shown on the chart, as long as the IRRs remain above the 10% cost of capital the projects remain economically attractive, at least theoretically. However, as IRRs approach this economic floor, project acceptance rates will go down. The industrial projects are shown to remain in an economically attractive range throughout the forecast period. However, the small, packaged 150 kW system becomes uneconomic after 2001 – based on the *current* high costs projected for these systems *in the base case*.

Figure 3-2.2. Internal Rate of Return for Different CHP Types and Sizes as a Function of Annual Forecast Electric and Gas Rates



3.3 Market Penetration Scenarios

The market penetration forecast is based on the CHP economic analysis, the market potential estimated in the second phase of this project and the historical rate of market penetration by size and market for CHP.

Market Potential Summary

The second phase of this project provided a detailed evaluation of the total potential for CHP in the California industrial and commercial market sectors. Total potential was determined as a function of size, market application, and thermal to electric energy utilization ratios—a measure of the ability of the application to utilize the waste heat generated by on-site power generation.

Table 3-3.1 summarizes the existing CHP in the commercial and industrial sectors as a function of size. Table 3-3.2 summarizes the remaining potential developed in section 2, Market Potential, of this project. For the cumulative penetration levels, it was assumed that the current remaining potential grows at 2% per year over the forecast period.

Table 3-3.1. Existing CHP in the Commercial and Industrial Sectors

Summary of Existing CHP for Industrial and Commercial Only						
	Commercial		Industrial		Total	
	Sites	MW	Sites	MW	Sites	MW
50-250 kW	195	19	21	3	216	22
250-1,000 kW	51	28	24	12	75	40
1-5 MW	37	78	36	101	73	179
5-20 MW	14	125	45	390	59	515
> 20 MW	16	552	84	5,147	100	5,699
Total	313	802	210	5,652	523	6,454

note: There are 145 existing projects less than 50 kW with a capacity of 2.7MW

Table 3-3.2. Remaining Potential for CHP in the Commercial and Industrial Sectors

Summary of Remaining Potential CHP						
	Commercial		Industrial		Total	
	Sites	MW	Sites	MW	Sites	MW
50-250 kW	23,559	2,105	0	0	23,559	2,105
250-1,000 kW	2,638	1,438	1,280	648	3,918	2,086
1-5 MW	534	993	582	1,184	1,116	2,177
5-20 MW	69	446	104	1,055	173	1,501
> 20 MW	15	619	51	3,620	66	4,240
Total	26,815	5,602	2,017	6,506	28,832	12,108

Historical Market Penetration Rates

The CHP market has shown both a tremendous growth period in the 1980s followed by a decline and a period of market stability. Figures 3-3.1 and 3-3.2 show the historical market penetrations by size category in terms of units added per year and MW added per year respectively. Table 3-3.3 shows the average market penetration rates for CHP in the California market during the most recent stable period (1991-1996). During this period, slightly over 400 MW/year of CHP were added. This penetration rate was used as the initial penetration level for the base case forecast and was adjusted based on the changes in the IRRs for each category over the forecast period.

Figure 3-3.1 Historical Market Penetration of CHP as a Function of Size (Units/year)

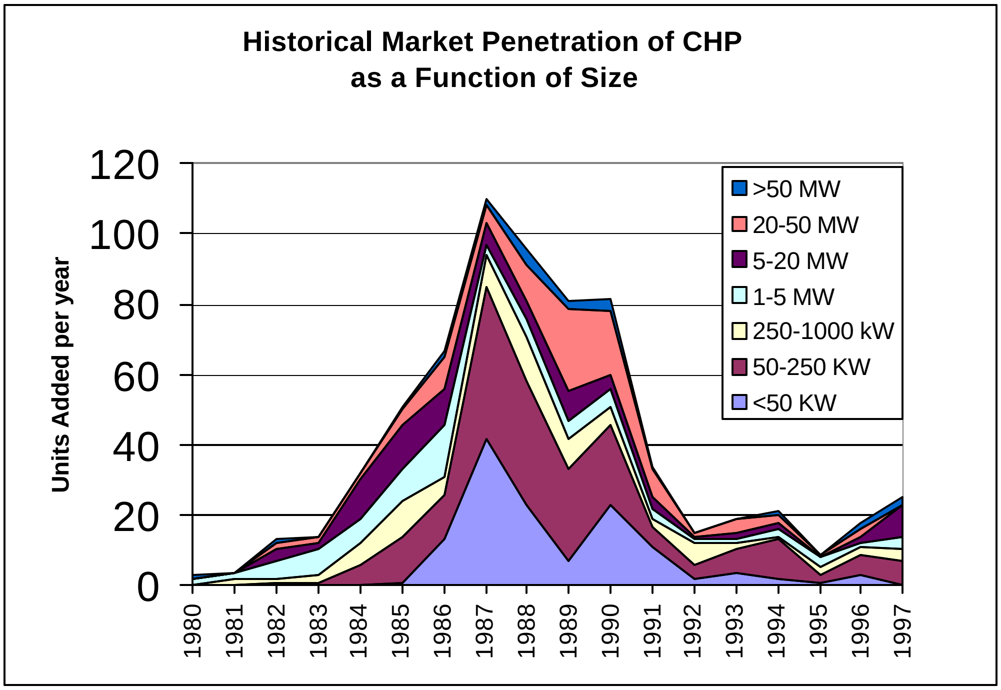


Figure 3-3.2. Historical Market Penetration of CHP as a Function of Size (MW/year)

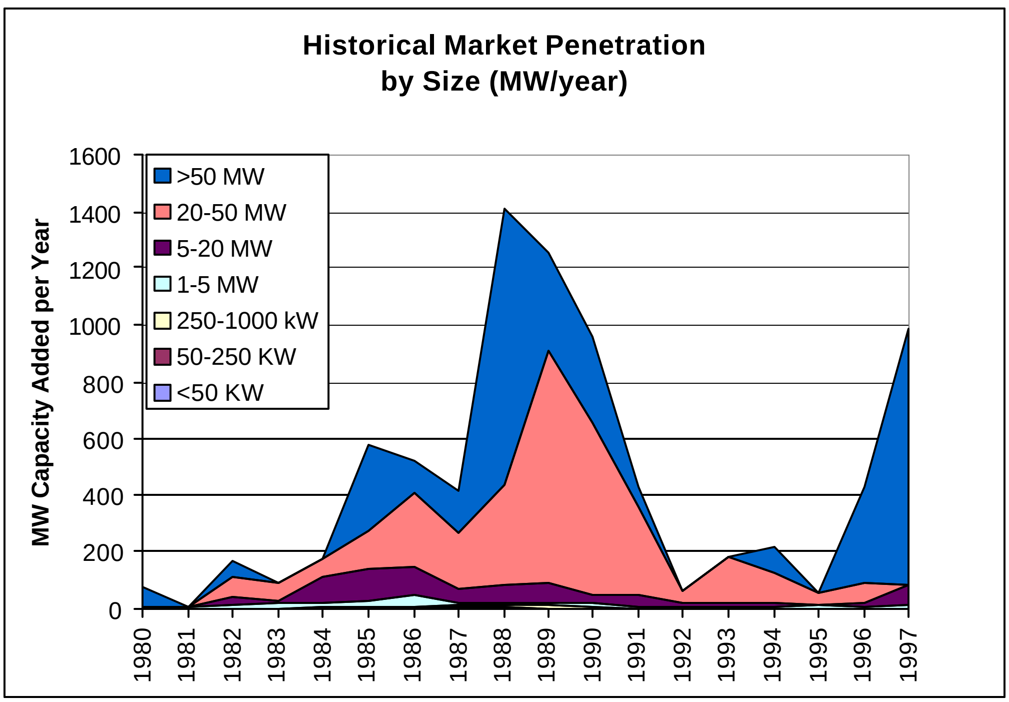


Table 3-3.3. Average CHP Penetration Rates in the 1990s

	1991-1996 Average Penetration	
	Units/year	MW/year
50-250 kW	1.8	0.79
250-1000 kW	6.2	1.15
1-5 MW	2.2	4.87
5-20 MW	2.3	29.42
> 20 MW	4.6	378.57
Total	17.0	414.79

Base Case Scenario

The base case market penetration forecast was developed using the IRR calculations based on the CHP technology cost and performance and the CEC electricity and gas price forecasts. The 1991-1996 historical market penetrations were used as the initial penetration rate. This initial penetration rate was adjusted as a function of the calculated IRRs in each year. These adjustment factors are based on the assumption that penetration would equal the observed historical penetration for equal IRR and that penetration would be zero at an IRR of 8% or below. Penetration rates were interpolated on a linear basis between these levels. Therefore, the initial period IRRs defined as producing 100% of the initial period market penetration with proportionate adjustments down to zero market penetration at an IRR of 8%.

Figure 3-3.3 shows the year-by year base-case market penetration forecast by size category in terms of megawatts of capacity added per year. Table 3-3.4 shows the cumulative penetration in both capacity added and number of projects and the cumulative penetration of the remaining potential. The cumulative penetration is calculated on the basis of capacity in megawatts, and the current potential calculated in the previous section of the report is assumed to increase during the forecast period at 2% per year.

Figure 3-3.3. Base Case CHP Market Penetration Forecast

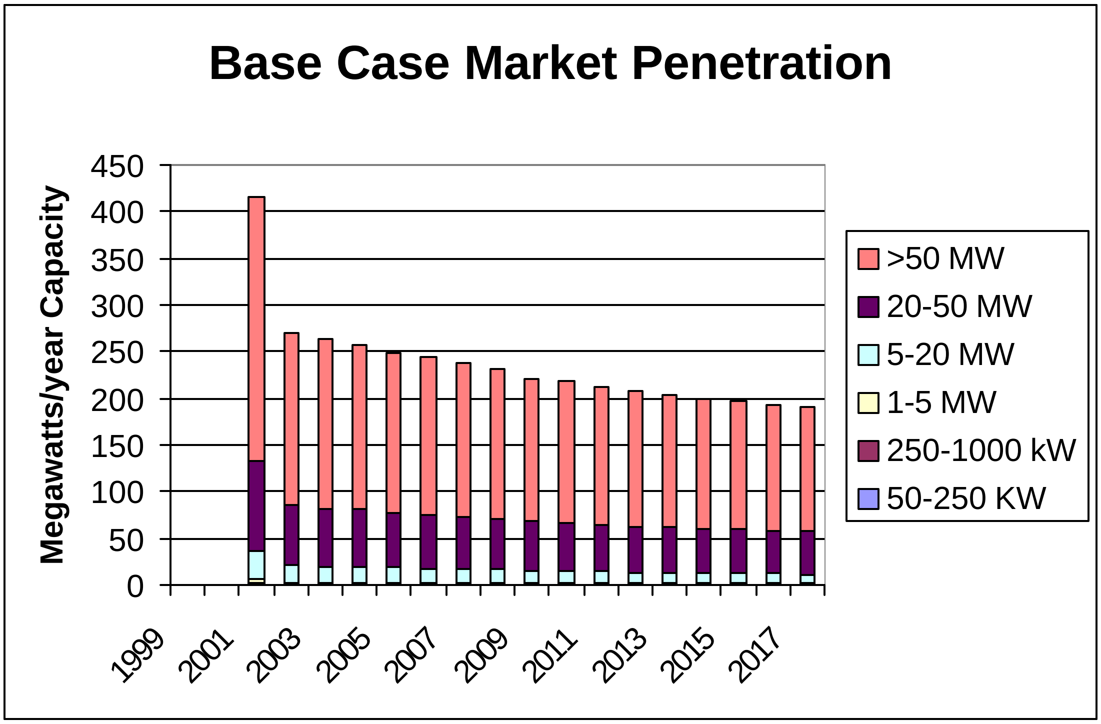


Table 3-3.4. Base Case Cumulative Additions in Capacity and Projects and Percent Saturation of Total Remaining Available Market

CHP Category by Size	Cumulative Penetration in MW	Cumulative Penetration in Units	% of Total Market Penetrated
50-250 kW	0.8	8	0.03%
250-1000 kW	7.7	14	0.25%
1-5 MW	32.7	14	1.01%
5-20 MW	243.5	27	10.92%
> 20 MW	3724.7	45	59.12%
Total	4009.4	108	22.28%

High Market Penetration Case

The base case analysis shows a declining level of market penetration and very low penetration rates for the smaller size ranges of CHP, almost none for the smallest category. This base case forecast does not include the effects of improved technology, streamlined siting and permitting, more intensive marketing efforts, regulatory initiatives that provide incentives for economically beneficial projects. To provide a basis for evaluating the impacts of State and Federal programs, we have defined a high market penetration case. This case has the following changes from the base case:

- **CHP technology improvement** – This includes efficiency improvements, package cost reductions, and reductions in environmental control technology costs that will be the result of expanded research, development and demonstration programs.

- **Streamlined Project Implementation** – This includes faster project implementation, lower interconnect costs from standardization, and lower installation costs due to a more stable and competitive market for CHP.

- **CHP Initiatives** – Financial incentives provided by either the Federal or State government are being discussed for CHP. The rationale for these incentives is that increased penetration of economically viable CHP has both private benefits that accrue to the project participants and social benefits that accrue to the public.

- **Higher marketing effort** – The base case penetrations were based on the observed penetration rates and economic values in the 1990s. The competitive market has created a larger number of energy service providers that will be contacting customers and marketing energy service options including CHP. With higher marketing effort, market penetration rates will be higher for a given level of economic value. As marketing efforts and government programs are implemented, customer confidence in the technology will go up reducing the very high risk premium that has been placed on CHP project decision-making.

High Market Case Approach and Assumptions

The high market case for CHP is based on two types of changes to the economic assumptions. Changes to the cost and performance of the CHP system improve the IRR and thereby raise market penetration rates according to the historical relationship between IRR and market penetration that was used for the base case. Changes to marketing effort and customer confidence will change the market penetration rates for a given project IRR. We looked at three incremental levels for these changes: First, we looked at an improved set of CHP technology performance and package costs; installation costs remained unchanged. Secondly, we looked at the cost reduction impacts of the CHP initiatives that are designed to streamline siting, standardize interconnection, and reduce the site related costs. One aspect of the CHP initiatives involves either a tax credit or accelerated depreciation. We represented this as a simple 10% reduction in overall capital costs. Finally, we increased the historically observed market response rates for a given level of IRR. The market penetration impacts of these changes are shown incrementally as follows:

- Step 1: improved CHP technology package
- Step 2: Improved technology plus CHP initiatives
- Step3: Improved technology, CHP initiatives, plus improved rates of market response.

The Step 1 improvements to CHP technology are based on the following changes to the technology assumptions:

- Microturbines will reach their high volume cost target goals and improve their overall electrical efficiency rates from 26% to 29%. These rates correspond to engine generator efficiencies quoted by the manufacturers of 30-34% based on the lower heating value of the fuel.
- Small and large gas engines will reach higher efficiencies approaching the efficiencies of diesel cycle engines.
- Small turbines will improve efficiencies as a result of improved materials that can withstand higher temperatures and recuperation that raises overall electric efficiencies from 29% to 37%.
- The larger turbine efficiencies are increased using combined cycle technology to provide electric efficiencies of 44%.
- Package costs for engines and turbines will be reduced by 14-25%.

The Step 2 improvements to CHP turnkey costs are based on the following changes in the installation cost assumptions:

- Interconnect costs cut in half for all technologies, reduced by two-thirds for the smallest microturbine or small engine installations
- Selective catalytic reduction costs cut in half
- Contractor markups reduced from 15-20% to 10% across the board to reflect a high volume competitive market
- Construction lead times reduced by 6 months resulting in lower carry charges for interest during construction
- A 10% reduction in overall capital costs to reflect a tax credit or accelerated cost recovery on depreciation for tax purposes.

Step1 and Step 2 changes represent all the changes to the technology assumptions. These combined changes are shown in Table 3-3.5. Table 3-3.6 shows the change in paybacks and IRR for the initial year due to the Step 1 and Step 2 changes.

Table 3-3.5. High Case Technology Specifications

Representative Onsite Generation Cost and Performance	Microturbine	Gas Engine	Fuel Cell	Gas Engine	Gas Turbine	Gas Turbine
Size kW	50	100	200	800	5,000	25,000
Heat Rate (Btu/kWh HHV)	11,741	11,147	6,205	9,382	9,125	7,699
Recov. Exhaust Heat (Btu/kWh)	4600	1600		1200	3709	2800
Recov. from Coolant (Btu/kWh)		2600	1600	2500		
Package Cost ($/kW)	$350	$500	$900	$300	$300	$300
Heat Recovery	$150	$100	$75	$75	$75	$75
Emission Controls	$0	$70	$0	$29	$51	$50
Project management	$18	$25	$45	$15	$15	$15
Site & Construction Management	$25	$35	$63	$21	$21	$21
Engineeering	$14	$20	$20	$12	$12	$12
Civil	$50	$75	$100	$38	$15	$13
Labor/Installation	$70	$100	$120	$38	$45	$45
CEMS	$0	$0	$0	$0	$30	$20
Fuel Supply-compressor	$40	$0	$0	$0	$20	$15
Interconnect/Switchgear	$50	$75	$38	$31	$10	$3
Contingency	$18	$25	$27	$15	$15	$15
General Contractor Markup	$78	$103	$139	$57	$61	$58
Bonding/Performance Guarantee	$24	$31	$14	$17	$18	$18
Carry Charges during Constr.	$28	$37	$49	$21	$44	$42
Basic Turnkey Cost ($/kW)	$914	$1,195	$1,589	$668	$732	$702
CHP Initiative 10% Cost Reducti	$822	$1,076	$1,430	$601	$659	$632
O&M Cost $/kWh	$0.010	$0.014	$0.005	$0.011	$0.003	$0.003

Table 3-3.6 Impact of Changing CHP Cost and Performance Assumptions on Initial Year Payback and IRR

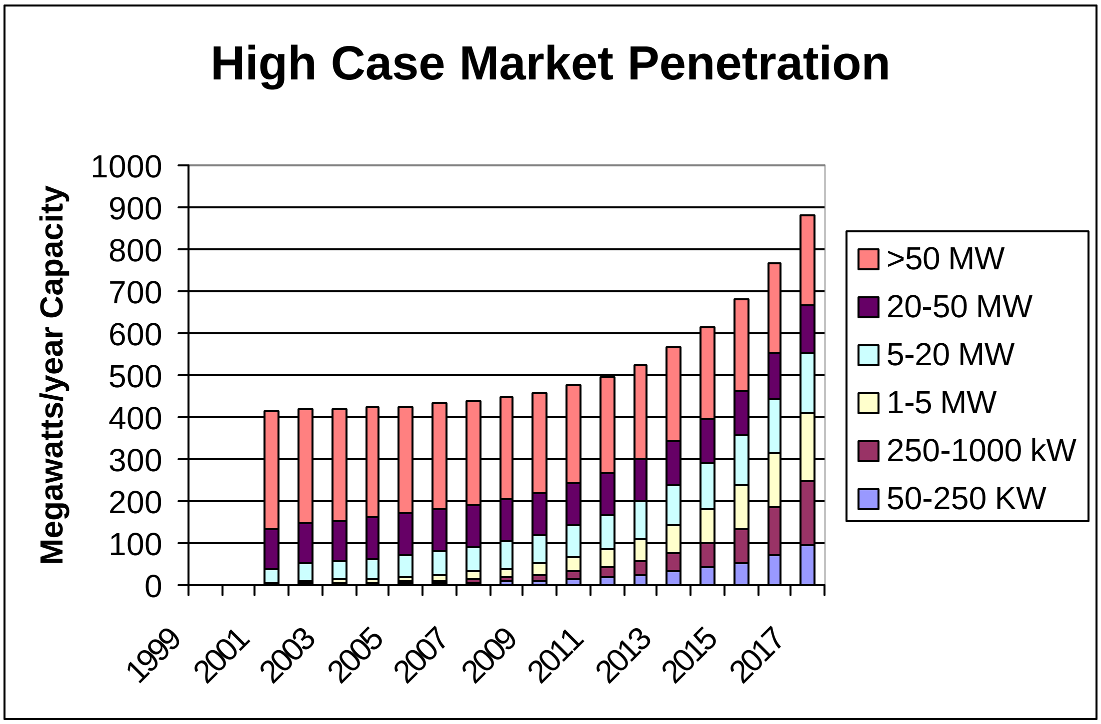
Case Results		Base Case		Improved Package		Total Cost and Perf. Improvements	
Technology	CHP Size	Payback Years	IRR	Payback Years	IRR	Payback Years	IRR
Microturbine	150 kW	3.68	24.01%	2.78	34.02%	2.06	47.49%
Gas Engine	2.25 MW	2.73	36.31%	2.37	41.99%	1.88	53.11%
Gas Turbine	10 MW	2.84	35.15%	2.23	44.98%	1.77	56.74%
Gas Turbine	50 MW	2.16	46.52%	2.07	48.51%	1.66	60.66%

The Step 3 change represents an adjustment factor to the observed penetration rates for each CHP size range. For CHP projects under 1 MW, we assumed that the market penetration rates given no change in IRR would increase exponentially over the forecast period to a level 200 times the historical rate by the year 2017. This factor is then multiplied by the penetration rate calculated as a result of the change in the IRR. For the 1-5 MW size range, market penetration rates as a function of IRR are projected to increase over the forecast period to a factor of 50 by the final year. For the 5-20 MW class, the factor is 5. For the 20-50 MW size, the factor is 1.5, and for all larger projects there is assumed to be no increase in market response. These factors were selected based on a qualitative assessment of the level of market penetration historically observed and the increase in companies addressing the smaller packaged market segments. The very low market penetrations in the smaller size categories are due only in part to lower economic value. Part of the reason for low penetration in these market segments has been the lack of marketing effort to develop projects in these small sizes. Most of the marketing effort has gone into the development of larger CHP projects.

High Case Market Penetration Results

The combined impact of each of the three sets of changes for the high penetration case is shown in Figure 3-3.4. Market penetration in MW rises over the forecast period as the marketing effort in the smaller sized systems begins to provide higher response rates in the later years. Market penetration of the largest systems (above 50 MW) falls off over the forecast period as market saturation approaches 100%.

Figure 3-3.4. High Case CHP Market Penetration Forecast



The cumulative market penetrations and saturations for the remaining market for the high market case in total and the three incremental steps in constructing the case are shown in Table 3-3.7

Table 3-3.7. High Case Cumulative Additions in Capacity and Projects and Percent Saturation of Total Remaining Available Market

CHP Category by Size	Cumulative Penetration in MW	Cumulative Penetration in Units	% of Total Market Penetrated
Base Case			
50-250 kW	0.8	8	0.03%
250-1000 kW	7.7	14	0.25%
1-5 MW	32.7	14	1.01%
5-20 MW	243.5	27	10.92%
> 20 MW	3724.7	45	59.12%
Total	4009.4	108	22.28%
Better Package Cost and Performance (Step 1)			
50-250 kW	2.6	26	0.08%
250-1000 kW	11.0	20	0.35%
1-5 MW	46.7	19	1.44%
5-20 MW	393.6	44	17.65%
> 20 MW	4122.1	50	65.43%
Total	4575.9	159	25.43%
Better CHP Package and CHP Initiatives (Step 1-2)			
50-250 kW	13.0	130	0.41%
250-1000 kW	15.9	29	0.51%
1-5 MW	67.7	28	2.09%
5-20 MW	542.7	61	24.34%
> 20 MW	5503.9	66	87.36%
Total	6143.1	314	34.14%
High Market Scenario Total (Step 1,2,3)			
50-250 kW	389.9	3904	12.46%
250-1000 kW	568.9	1031	18.36%
1-5 MW	793.7	331	24.54%
5-20 MW	1319.7	148	59.18%
> 20 MW	5816.5	75	92.33%
Total	8888.7	5490	49.40%

CHP Benefits

Emission rates for central stations are changing rapidly, mostly because of the Best Available Control Technologies (BACT) and the Best Available Retrofit Control Technologies (BARCT) rules that are being implemented state-wide[35]. Central station emission rates for year 2000 have been assumed to be boilers meeting BARCT; for year 2005, rates are assumed to be the operation of the high efficiency combustion turbine siting cases currently before CEC. Rates considered representative of displaced generation are .15 lbs/MWh[36] for year 2000 and .042 lbs/MWh[37] for year 2005. These numbers represent conservative estimates of the grid and do not include any out-of-state NOx contribution, or any non-BARCT boilers[38]. SCR is assumed for combustion turbines and combined cycle units, low NOx burners for gas boilers, flue gas recirculation for boiler offsets.

CHP NOx numbers in the tables that follow represent NOx reduction strategies for each technology that reasonably available, in other words, strategies that are available and relatively cost-effective today. For the 50kW – 250kW engines, the control is stoichiometric engine with a three-way catalyst; the 250kW – 1MW engine is a lean-burn engine without SCR; the gas turbines less than 20MW in size are assumed to use SCR to achieve 9ppm of NOx at 15% oxygen; and the turbines larger than 20 MW are assumed to use SCONOx.

<u>Energy and Economic Savings</u>

The base case creates 4,009 MW of CHP by 2017, the end of the forecast period. The high case adds 8,889 MW by 2017. Estimates of CHP energy savings and user savings are presented in Table 3-3.8, for the Base Case and High Case. By 2017, the Base Case saves California consumers 149 trillion Btu/year and $339 million/year. The comparable 2017 figures for the High Case are 347 trillion Btu/year and $971 million/year. The energy savings represent 52 to 56% of the energy required the utility industry to generate the same quantity of power. The net user savings after all costs of CHP construction and operation are subtracted represent 25% of the CEC forecast industrial cost of electricity in 2017 for the Base Case – 33% in the High Case.

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[35] CARB, *Power Plant Siting and Best Available Control Technology*, June 1999

[36] Assumes 015 lbs/MMBtu at 10,000 Btu/kWh. Data from private correspondence with Matt Layton of CEC, August 1999

[37] Assumes 006 lbs/MMBtu at 7,000 Btu/kWh. Data from private correspondence with Matt Layton of CEC, August 1999

[38] New owners of some of the recently transferred utility generators, such as the Encina Power Station, are filing variances to extend the time they have to comply with BARCT. Cabrillo Power, *San Diego County APCD Hearing Board Petition for Variance*, September 7, 1999.

Table 3-3.8 Energy and Economic Savings from CHP Deployment

Year	Base Case				High Case			
	CHP Generation GWh/year	Net Energy Saved 10^12 Btu	User Savings $Million/year	User Savings ¢/kWh	CHP Generation GWh/year	Net Energy Saved 10^12 Btu	User Savings $Million/year	User Savings ¢/kWh
2001	2,906	15	$88	3.02	2,906	17	$103	3.54
2002	4,803	25	$88	1.82	5,840	34	$136	2.34
2003	6,651	35	$118	1.77	8,783	51	$200	2.28
2004	8,460	45	$146	1.72	11,754	68	$262	2.23
2005	10,206	54	$168	1.65	14,729	85	$318	2.16
2006	11,911	63	$191	1.60	17,749	102	$375	2.11
2007	13,575	72	$211	1.56	20,823	119	$429	2.06
2008	15,191	80	$228	1.50	23,955	137	$480	2.00
2009	16,743	89	$239	1.43	27,140	155	$522	1.92
2010	18,268	97	$256	1.40	30,463	174	$574	1.89
2011	19,750	105	$267	1.35	33,928	194	$620	1.83
2012	21,200	112	$278	1.31	37,595	214	$670	1.78
2013	22,628	120	$292	1.29	41,543	236	$726	1.75
2014	24,026	127	$302	1.26	45,826	260	$779	1.70
2015	25,401	134	$312	1.23	50,551	286	$836	1.65
2016	26,757	142	$324	1.21	55,870	314	$901	1.61
2017	28,097	149	$335	1.19	61,949	347	$971	1.57
Energy Saved Btu/kWh				5,295				5,602

Emissions Benefits

\Estimates of CHP NOx reductions are as follows, for basecase (BC) and high case (HC) are presented in Table 3-3.9. Negative numbers indicate reductions of tons of NOx. No out-of-state NOx is included in this analysis. The reductions appear mostly in the large turbines with SCONOx, which in combination with boiler offsets create a net benefit. Because these large systems represent the majority of MW, particularly in the base case, the NOx reductions they create make an overall NOx benefit for future CHP. The positive NOx numbers in the smaller technologies are illustrative of California's low in-state emission rate. These results should not be considered definitive, however, but only illustrative. Dispatch modeling which accounts for the dispatch order of new generation and emission rate changes for existing boilers is needed to give a firm basis for in-state grid emission rates.

Table 3-3.9 NOx Savings from CHP Deployment

CHP unit size	*Net NOx Tons yr 2000 Basecase*	*Net NOx Tons yr 2000 High case*	*Net NOx Tons yr 2005 Basecase*	*Net NOx Tons yr 2005 High case*
50-250 kW	(0.1)	(36.3)	0.2	101.8
0.25-1 MW	16.5	1221.0	19.2	1422.5
1-5 MW	4.7	113.7	17.9	435.1
5-20 MW	(31.3)	(169.8)	67.3	364.6
>20 MW	(3216.9)	(5023.5)	(1708.7)	(2668.3)
Totals	(3227.1)	(3895.0)	(1604.1)	(344.3)

Estimates of CHP CO_2 reductions are presented in Table 3-3.10, for basecase (BC) and high case (HC) in 2000 and 2005:

Table 3-3.10 CO_2 Savings from CHP Deployment

CHP unit size	*CO2 Emissions Instate 2005 Basecase*	*CO2 Emissions Instate 2005 High case*	*CO2 Emissions Grid 2005 Basecase*	*CO2 Emissions Grid 2005 High case*
50-250 kW	863	424,029	(77)	(37,661)
0.25-1 MW	52	3,826	(9,045)	(669,846)
1-5 MW	(2,329)	(56,588)	(46,538)	(1,130,784)
5-20 MW	30,961	167,780	(298,616)	(1,618,202)
>20 MW	(2,447,539)	(3,822,088)	(7,488,376)	(11,693,879)
Totals	(2,417,993)	(3,283,041)	(7,842,653)	(15,150,372)

It is evident from the totals that the difference between the base case and the high case is significant. The Department of Energy CHP Challenge is to double CHP by 2010. That is achieved by the high case in 2012 (assuming the same MW in 1998 through 2000 as are predicted for the base case year 2001), but not by the base case, since doubling requires another 6457 MW must be built. Over the entire study period from 2001 to 2017, the high case saves an additional 215,000 GWh of electricity; generates an additional net savings of 1330 TBtu; and an additional net user savings of over $5 billion.

Reliability Benefits

The reliability benefits are calculated according to the methodology defined in Section 2.2 Estimation of the Benefits of Existing CHP. The value of increased reliability due to onsite generation is as follows:

Reliability Benefit = (Expected Outage Hours/yr) x (Outage Cost/hr) x (Onsite gen. Availability factor)

As defined in the Section 2.2, the expected annual reliability benefit is estimated at $114/kW of CHP capacity for commercial systems and $28.50/kW for industrial systems. The market penetration estimates made in this section were developed as a function of CHP size – the commercial and industrial markets were combined by size in this approach. Therefore, to estimate the reliability benefit of the cumulative market penetration estimates, we assume that the share of commercial and industrial systems is proportional to the share of the systems in each size range identified as the remaining CHP technical market potential. In the smallest size range, 50-250kW, commercial systems comprise 100% of the assumed potential. In the largest size range, greater than 20 MW, commercial systems comprise 15% of the total and industrial systems comprise 85%. A weighted average reliability benefit was calculated for each size range as shown in Table 3-3.11.

Table 3-3.11 Reliability Benefit of Base and High Case Scenarios

CHP Category by Size	Cumulative Penetration in MW	Weighted Average Annual Outage Cost/kW *	Annual Reliability Benefits
Base Case			
50-250 kW	0.8	$114.00	$90,407
250-1000 kW	7.7	$87.45	$671,778
1-5 MW	32.7	$67.51	$2,205,220
5-20 MW	243.5	$53.91	$13,128,452
> 20 MW	3724.7	$40.99	$152,685,784
Total	4009.4	$42.10	$168,781,640
High Case			
50-250 kW	389.9	$114.00	$44,446,388
250-1000 kW	568.9	$87.45	$49,747,362
1-5 MW	793.7	$67.51	$53,582,600
5-20 MW	1319.7	$53.91	$71,143,029
> 20 MW	5816.5	$40.99	$238,434,754
Total	8888.7	$51.45	$457,354,133

CHP capacity can provide grid support benefits to utility distribution companies (UDC). Optimally placed CHP or other forms of distributed generation can defer the need for distribution capacity investment. These benefits are very site specific and there is currently no accepted mechanism for valuing them. In a restructured electricity market with performance based ratemaking for UDCs, there will be opportunities for UDCs and customers to negotiate for grid support. UDCs can defer substation upgrades and other distribution investments with distributed generation placed at the load center. A typical substation upgrade costs about $200/kVA for the substation transformer, substructure, buswork, protective devices, and other costs. A typical 10-16 MVA upgrade costs $2-3 million with a 2-year lead-time. Planners must forecast the substations that will need upgrading in advance; inaccuracies in forecasting lead to overbuilding or constrained areas. If 10% of cumulative CHP additions are used to avoid substation investments, then the grid support benefit would be $80 to $180 million total. There is really no way to further quantify this benefit without the emergence of a procedure for utilities to identify sites and negotiate contracts with generator.

3.4 Conclusions

California became the largest market for CHP in the United States during the 1980s as a result of very high utility costs and attractive rules for utility buy-back of CHP generated power. Several factors combined to end the huge penetration rates experienced in the late 1980s: environmental rules tightened; small system packagers left the business due to excessive costs for installation and maintenance and, in some cases, a poor track record in the field; utilities began to more effectively counter CHP development with economic deferral rates that were possible due to the low marginal cost of power in the increasingly competitive wholesale power market.

The transition of the California electricity market wholesale and retail competition are expected to lower real commercial and industrial average electric prices considerably once the transition cost recovery period is completed sometime in 2001 or 2002. According to the CEC forecast used for this analysis, average retail commercial costs will drop to 6.2 ¢/kWh and industrial costs will drop to 4.8 ¢/kWh. This price drop will occur fairly quickly after the end of the transition period.

The post transition economic climate will more closely resemble the situation that exists today in lower cost power states. In these states, current penetration of CHP is much lower than in the current high cost states, like California.

In the base case forecast, the future CHP penetration is expected to continue at a declining level over time based on the average penetration rates experienced during the 1991-1996 period after the end of the initial market boom period for a total incremental penetration of CHP of 4000 MW. Over 90% of this penetration will be in the largest industrial size category of 20 MW and above resulting in a market saturation of 59% of the remaining potential in this size range.

In the base forecast, penetration of smaller packaged cogeneration systems less than one megawatt will continue to be an extremely small percentage of total unrealized potential – less than 1% of total potential sites. It should be emphasized that the base-case forecast depends on the penetration of CHP at historical and forecast energy prices and does not take into account the aggressive market plans of energy service providers that plan to offer packaged microturbines or fuel cells at an attractive price to small customers.

The economics of the largest CHP systems will continue to be attractive. Penetration rates within this sector are forecast to equal two-thirds of the available, unrealized potential.

In the high penetration case, improvement to CHP package cost and performance, all else being equal, would raise cumulative CHP penetration over the forecast period from 4000 to 4575 MW – an increase of 14%. Adding the impacts of the various CHP initiatives to the improved technology would increase cumulative market penetration to 6143 MW – a total improvement compared to the base case of 53%. Finally, adding in the impacts of increased marketing effort and higher customer response rates provides for a cumulative CHP market penetration of 8,889 MW – a 222% increase compared to the base case. In the high case scenario, market saturation for the smallest sizes of CHP would increase from less than 1% to 12-18%. This increase represents almost 5000 small systems with a combined capacity of nearly 1 megawatt. Improvements in the middle range systems of 1-20 MW is also substantial, growing from 277 MW of cumulative penetration in the Base Case to 2113 MW in the High Case.

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Appendix 2-1 Distribution of Existing CHP by Fuel and Prime Mover

Prime Mover by 2 Digit SIC Code

		BS/T		CC		CT		fcel		RENG	
SIC2	SIC2 Name	# of Site	MW Capacity	# of Site	MW Capacity	# of Site	MW Capacity	# of Site	MW Capacity	# of Site	MW Capacity
1	Agricultural Production			1	6.5					5	6.344
13	Oil & Gas Extraction	4	117	3	394	50	1615.28			10	9.879
14	Nonmetallic Minerals, except fuels			1	55.4	1	45				
20	Food & Kindred Products	7	95.751	8	646	13	256.405	1	0.2	10	12.289
22	Textile Mill Products									1	1.05
24	Lumber & Wood Products	17	257.08	1	49.5						
26	Paper & Allied Products	1	13.5	5	158.6	8	364			1	1.4
27	Printing & Publishing					2	5.02			2	5.2
28	Chemicals & Allied Products	3	105	2	126.6	6	161.3			2	2.242
29	Petroleum & Coal Products	3	58.5	5	650.42	5	209.3				
30	Rubber & Misc. Plastic Prods.									1	0.387
32	Stone, Clay & Glass Products	2	51			1	48.4			3	2.3
33	Primary Metal Industries									3	0.395
34	Fabricated Metal Products									12	1.843
35	Machinery & computer Equip.									4	2.565
36	Electric & Electronic Equip.									4	6.978
37	Transportation Equipment			1	8.9	2	6				
39	Misc. Manufacturing Industries			1	11.477					4	3.26
42	Motor Freight Transportation & Warehousing					2	56				
44	Water Transportation									1	1.3
45	Transportation by Air			1	30						
46	Pipelines, except Natural Gas					1	17				
48	Communications					1	6				
49	Electric, Gas, Sanitary Services					1	49.4			15	46.31
51	Wholesale Trade - Non-durable goods									2	0.325
54	Food Stores									1	0.085
55	Automotive Dealers & Gasoline Service Stations									1	0.1
57	Furniture, Home Furnishing & Equipment Stores									2	1.475
58	Eating and Drinking Places							1	0.04	10	0.918
65	Real Estate					3	10.4			33	4.82
70	Hotels, Rooming houses, Camps & other Lodgings					2	1.9	1	0.2	54	7.329
72	Personal Services							1	0.08	67	1.047
73	Business Services			1	29					1	3.375
75	Automotive Repairs, Services & Parking									1	0.06
79	Amusement & Recreational Services			1	49.8	1	0.11			45	5.577
80	Health Services			3	85.406	8	10.639	3	1	41	17
82	Educational Services			4	91.35	8	80.832	1	0.2	102	25.929
83	Social Services									2	0.22
86	Membership Organizations									1	0.48
87	Engineering & Management Services	1	3			1	3.8			1	1.3
89	Misc. Services									2	0.07
91	Executive, Legislative & General Government									7	5.079
92	Justice, Public Order, Safety			1	28.14			1	0.2	3	3.725
95	Environmental Quality & Housing							1	0.2	2	8.68
96	Administration of Economic Programs					1	3.5				
97	National Security & International Affairs	3	107.2			2	1.6			2	2.595
		41	808.031	39	2421.093	119	2951.886	10	2.12	458	193.931

	Industry	AG		BMTH		COAL		NG		O-ES		OIL
SIC2		# of Site	MW Capacity	# of Site	MW Capacity	# of Site	MW Capacity	# of Site	MW Capacity	# of Site	MW Capacity	# of Site
1	Agricultural Production							6	12.83			
13	Oil & Gas Extraction					3	115.5	60	2011.48			2
14	Nonmetallic Minerals, except fuels							2	100.4			
20	Food & Kindred Products	2	25			2	57.5	35	928.13			
22	Textile Mill Products							1	1.05			
24	Lumber & Wood Products					1	44	1	49.5	2	32.5	
26	Paper & Allied Products							14	524			
27	Printing & Publishing							4	10.22			
28	Chemicals & Allied Products					1	96	7	235.501			1
29	Petroleum & Coal Products							7	656.72			
30	Rubber & Misc. Plastic Prods.							1	0.387			
32	Stone, Clay & Glass Products							4	50.7	1	27	
33	Primary Metal Industries							3	0.395			
34	Fabricated Metal Products							12	1.843			
35	Machinery & computer Equip.							4	2.565			
36	Electric & Electronic Equip.							3	6.078			1
37	Transportation Equipment							3	14.9			
39	Misc. Manufacturing Industries							4	3.26			
42	Motor Freight Transportation & Warehousing							2	56			
44	Water Transportation							1	1.3			
45	Transportation by Air							1	30			
46	Pipelines, except Natural Gas							1	17			
48	Communications							1	6			
49				3	4.15			10	88.75	3	2.81	
51	Wholesale Trade - Non-durable goods							2	0.325			
54	Food Stores							1	0.08			
55	Automotive Dealers & Gasoline Service Stations							1	0.1			
57	Furniture, Home Furnishing & Equipment Stores							2	1.47			
58	Eating and Drinking Places							10	0.88	1	0.065	
65	Real Estate							36	15.22			
70	Hotels, Rooming houses, Camps & other Lodgings							56	9.419	1	0.011	
72	Personal Services							67	1.117	1	0.011	
73	Business Services							2	32.37			
75	Automotive Repairs, Services & Parking							1	0.06			
79	Amusement & Recreational Services							46	55.4	1	0.03	
80	Health Services							55	114.03			
82	Educational Services							112	197.99	3	0.22	
83	Social Services							2	0.22			
86	Membership Organizations							1	0.48			
87	Engineering & Management Services							3	8.1			
89	Misc. Services							2	0.07			
91	Executive, Legislative & General Government							7	5.07			
92	Justice, Public Order, Safety							5	32.06			
95	Environmental Quality & Housing			1	7.5			2	1.38			
96	Administration of Economic Programs							1	3.5			
97	National Security & International Affairs							7	111.39			
		2	25	4	11.65	7	313	608	5399.74	13	62.647	4

Appendix 2-2 User and Environmental Savings calculation sheets

Calculated Energy Savings

California CHP Capacity Type	Size	Number	Capacity MW	Electric Effic. %	Recov. Heat Btu/kWh	Heat Used %	CHP Avoided Energy Use MWh/y	Line loss	Total	Electric 10^12 Btu	Thermal 10^12 Btu	CHP Fuel Used 10^12 Btu	Net Savings 10^12 Btu	Fuel use for Power Gen Btu/MWh
Boiler	Gasfired Boiler	9	149	30%	4,551	80%	891,060	62,374.20	953,434	10.23	4.05	10.14	4.15	11.48
	Oilfired Boiler	4	61	33%	3,827	80%	366,000	25,620.00	391,620	4.20	1.40	3.79	1.82	
	Solid Fuel Boile	28	599	30%	4,551	80%	3,591,480	251,403.60	3,842,884	41.23	16.34	40.86	16.72	
CT	CT <1 MW	11	7	23%	7,872	70%	39,840	2,788.80	42,629	0.46	0.27	0.60	0.13	
	CT 1-20 MW	61	347	28%	5,754	70%	2,083,524	145,846.68	2,229,371	23.92	10.49	25.76	8.64	
	CT 20-50 MW	38	1,523	35%	4,192	80%	9,135,126	639,458.82	9,774,585	104.87	38.30	90.11	53.06	
	CT 50+MW	10	1,156	33%	4,300	90%	6,933,000	485,310.00	7,418,310	79.59	33.54	71.70	41.43	
CC	CC 1-20 MW	6	58	34%	4,500	70%	348,762	24,413.34	373,175	4.00	1.37	3.50	1.88	
	CC 20-50 MW	23	822	40%	3,510	80%	4,931,796	345,225.72	5,277,022	56.62	17.31	41.87	32.06	
	CC 50+ MW	10	1,541	48%	2,250	90%	9,246,000	647,220.00	9,893,220	106.15	23.40	65.61	63.94	
Fuel Cell	PAFC Fuel Cell	10	2	36%	3,000	60%	12,720	890.40	13,610	0.15	0.03	0.12	0.05	
Engine	R.Eng. <200 kV	413	54	25%	4,433	60%	322,440	22,570.80	345,011	3.70	1.07	4.40	0.37	
	R.Eng. ~1.5 MV	36	66	31%	4,095	70%	398,580	27,900.60	426,481	4.58	1.43	4.35	1.65	
	R.Eng >6MW	9	74	34%	2,818	80%	443,880	31,071.60	474,952	5.10	1.25	4.49	1.85	
Totals		668	6,457				38,744,208	2,712,095	41,456,303	444.79	150.27	367.31	227.75	
notes:										11.48	3.878427	9.48		

1. Existing CHP capacity from Hagler-Bailly database by prime mover, sorted into size categories with similar costs and efficiencies.
2. Electric efficiencies and recoverable heat available estimated from representative technologies (Boiler numbers are not finalized)
3. Amount of recoverable heat utilized was estimated judgmentally. Smaller projects assumed to use a lower percentage than larger projects.
4. CHP assumed to run **6438** hours per year based on comparison with historical data (after subtracting small power projects)
5. Utility average heat rate assumed to be **9894** Btu/kWh, line losses assumed to be 4%. (needs to be checked)
6. Line losses of **0.07** reciprocal **0.93**

Standard measures: **1000** MW/kW

Calculated User Savings

California CHP Capacity		Number	Capacity	Electric	Recov.	Heat Used	Capital	O&M Cost	Power	Thermal	Net	Utility	User
				Effic.	Heat		Cost		Cost	Credit	Power	Electric	Savings
Type	Size		MW	%	Btu/kWh	%	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$million/yr
Boiler	Gasfired Boiler	9	149	30%	4,551	80%	$1,000	$0.010	$0.066	($0.014)	$0.052	$0.070	$13.34
	Oilfired Boiler	4	61	33%	3,827	80%	$1,000	$0.010	$0.063	($0.011)	$0.051	$0.070	$5.77
	Solid Fuel Boile	28	599	28%	4,551	80%	$1,000	$0.010	$0.068	($0.014)	$0.055	$0.070	$46.32
CT	CT <1 MW	11	7	23%	7,872	70%	$1,000	$0.006	$0.073	($0.021)	$0.052	$0.100	$1.61
	CT 1-20 MW	61	347	28%	5,754	70%	$1,000	$0.004	$0.063	($0.015)	$0.048	$0.070	$39.13
	CT 20-50 MW	38	1,523	35%	4,192	80%	$900	$0.003	$0.052	($0.013)	$0.040	$0.060	$157.34
	CT 50+MW	10	1,156	33%	4,300	90%	$600	$0.003	$0.047	($0.015)	$0.033	$0.050	$102.17
CC	CC 1-20 MW	6	58	34%	4,500	70%	$1,200	$0.005	$0.061	($0.012)	$0.050	$0.070	$6.05
	CC 20-50 MW	23	822	40%	3,510	80%	$1,100	$0.004	$0.054	($0.011)	$0.043	$0.060	$71.08
	CC 50+ MW	10	1,541	48%	2,250	90%	$800	$0.004	$0.043	($0.008)	$0.035	$0.050	$116.13
Fuel Cell	PAFC Fuel Cell	10	2	36%	3,000	60%	$1,500	$0.010	$0.071	($0.007)	$0.065	$0.100	$0.38
Engine	R.Eng. <200 kW	413	54	25%	4,433	60%	$1,000	$0.015	$0.078	($0.010)	$0.068	$0.100	$8.80
	R.Eng. ~1.5 MW	36	66	31%	4,095	70%	$750	$0.010	$0.059	($0.011)	$0.048	$0.070	$7.30
	R.Eng >6MW	9	74	34%	2,818	80%	$750	$0.010	$0.057	($0.008)	$0.048	$0.060	$4.40
Totals/Averages		668	6,457	37%	3,775	83%	$866	$0.005	$0.052	($0.012)	$0.041	$0.058	$579.83

Assumptions:

Capital Recovery Factor	13.15%
CHP Fuel Cost ($/MMBtu	$3.00

notes:

1. Capital cost estimates based on ONSITE SYCOM data, fuel cell cost is net of available credits.
2. Capital recovery factor based on 15 year life 10% return
3. O&M costs based on ONSITE SYCOM data
4. Gas cost is assumed to be $3.00/MMBtu
5. Thermal cost savings based on comparison to gas fired boiler at 80% efficiency
6. Average utility power costs are based on the size of use.
7. Savings are estimated at 85% of the difference between utility and net CHP power costs to account for standby charges.

Calculation of Gross and Net NOx Emissions for California CHP

California CHP Capacity		Number	Capacity	CHP Output	Thermal	NOx Emissions	weighted avg NOx	weighted avg NOx emissions	NOx Emissions	Boiler Offset	weighted avg boiler offset	Electricity Offset	Including Line Loss	in-state Emission Rate	out-state Emission Rate	in-state Grid Offset	out-state Grid Offset	in-state Net NOx Emissions	out-state Net NOx Emissions
Type	Size		MW	MWh/y	10^12 Btu	lb/MWh		no solid fuel	10^6 lbs	10^6 lbs	lbs/MWh	MWh	MWh	lb/MWh	lb/MWh	10^6 lbs	10^6 lbs	Tons	Tons
Boiler	Gasfired Boiler	9	149	891,060	4.05	0.398	0.009	0.013	0.35	0.18		891,060	953434.2	0.46	1.56	0.44	1.49	(132.56)	(654.12)
	Oilfired Boiler	4	61	366,000	1.40	0.749	0.007	0.007	0.27	0.06		366,000	391620	0.46	1.56	0.18	0.61	15.53	(198.69)
	Solid Fuel Boiler	28	599	3,591,480	16.34	1.800	0.167	0.000	6.46	0.72		3,591,480	3842883.6	0.46	1.56	1.78	5.99	1,982.99	(119.17)
CT	CT <1 MW	11	7	39,840	0.27	0.150	0.000	0.001	0.01	0.01		39,840	42628.8	0.46	1.56	0.02	0.07	(12.90)	(36.22)
	CT 1-20 MW	61	347	2,083,524	10.49	0.124	0.007	0.060	0.26	0.46		2,083,524	2229370.7	0.46	1.56	1.03	3.47	(618.02)	(1,837.55)
	CT 20-50 MW	38	1,523	9,135,126	38.30	0.099	0.023	0.209	0.90	1.68		9,135,126	9774584.8	0.46	1.56	4.54	15.23	(2,655.60)	(8,002.57)
	CT 50+MW	10	1,156	6,933,000	33.54	0.103	0.019	0.167	0.72	1.47		6,933,000	7418310	0.46	1.56	3.44	11.56	(2,096.71)	(6,154.73)
CC	CC 1-20 MW	6	58	348,762	1.37	0.100	0.001	0.008	0.04	0.06		348,762	373175.34	0.46	1.56	0.17	0.58	(99.14)	(303.28)
	CC 20-50 MW	23	822	4,931,796	17.31	0.085	0.011	0.097	0.42	0.76		4,931,796	5277021.7	0.46	1.56	2.45	8.22	(1,393.96)	(4,280.64)
	CC 50+ MW	10	1,541	9,246,000	23.40	0.071	0.017	0.152	0.66	1.02		9,246,000	9893220	0.46	1.56	4.59	15.42	(2,479.86)	(7,891.73)
Fuel Cell	PAFC Fuel Cell	10	2	12,720	0.03	0.020	0.000	0.000	0.00	0.00		12,720	13610.4	0.46	1.56	0.01	0.02	(3.66)	(11.10)
Engine	R.Eng. <200 kW	413	54	322,440	1.07	0.444	0.004	0.025	0.14	0.05		322,440	345010.8	0.46	1.56	0.16	0.54	(32.01)	(220.74)
	R.Eng. ~1.5 MW	36	66	398,580	1.43	0.444	0.005	0.030	0.18	0.06		398,580	426480.6	0.46	1.56	0.20	0.66	(41.82)	(275.11)
	R.Eng >6MW	9	74	443,880	1.25	0.444	0.005	0.034	0.20	0.05		443,880	474951.6	0.46	1.56	0.22	0.74	(39.15)	(298.96)
Totals		668	6,457	38,744,208	150.27		0.274	0.804	10.60	6.57	0.17	38,744,208	41,456,303			19.24	64.60	(7606.87)	(30284.61)

Notes:

1 Gas fired boiler emissions are based on EPA AP-42 small boiler low NOx burner (35 lbs/10^6 SCF) (assumed 1030 Btu/scf) and then converted to MWh using generation efficiency
2 Coal fired boiler emissions are based on EPA AP-42 bituminous, dry-bottom, wall-fired NSPS 12 lb/ton of coal (22 10^6 Btu/ton)
3 Oil fired boiler emissions are based on EPA AP-42 #2 oil boiler w LNB/FGR 24 lb/1000 gal of fuel
4 CT and CC emissions are based on an average observed results of testing on SCR by EPA in AP-42 = .01 lbs/mmbtu
5 Engine emissions based on 1.0 g/bhp-hr (not the current BACT)
6 Fuel Cell emissions from Task 1 report
7 Avoided boiler emissions based on EPA AP-42 small gas boiler with flue gas recirculation (50 lbs/10^6 SCF)

size	cap factor	basecase MW	high case MW	basecase MWh	high case MWh	CHP Fuel MMbtu/MWh	Boiler Fuel MMbtu/MWh	Net fuel btu/MWh	CO2 lb/10^6 Btu	Emission rate	CHP tons/MWh CO2	CHP tons CO2-BC	CHP tons CO2-HC	Instate 2005 CO2 Offset - BC	Instate 2005 CO2 Offset - HC	OOstate 2005 CO2 Offset - BC	OOstate 2005 CO2 Offset - HC	CO2 Emissions Instate 2005-BC	CO2 Emissions Instate 2005-HC	CO2 Emissions OOstate 2005-BC	CO2 Emissions OOstate 2005-BC
50-250kW	0.7	0.79	389.88	4,863	2,390,748	13.65	(2.66)	10.99	120.00	1318.6	0.659	3,206	1,576,201	2,344	1,152,172	3,283	1,613,862	863	424,029	(77)	(37,661)
250kW-1MW	0.7	7.68	568.89	47,107	3,488,438	10.92	(2.87)	8.05	120.00	966.1	0.483	22,754	1,685,006	22,702	1,681,181	31,799	2,354,852	52	3,826	(9,045)	(669,846)
1-5MW	0.8	32.67	793.73	228,926	5,562,457	10.12	(2.25)	7.86	120.00	943.5	0.472	107,997	2,624,124	110,326	2,680,711	154,535	3,754,908	(2,329)	(56,588)	(46,538)	(1,130,784)
5-20MW	0.8	243.53	1,319.67	1,706,636	9,248,255	12.36	(4.03)	8.33	120.00	1000.1	0.500	853,440	4,624,786	822,478	4,457,006	1,152,056	6,242,987	30,961	167,780	(298,616)	(1,618,202)
>20MW	0.8	3,724.70	5,816.51	26,102,708	40,762,097	10.34	(3.87)	6.47	120.00	776.3	0.388	10,132,122	15,822,364	12,579,661	19,644,451	17,620,498	27,516,243	(2,447,539)	(3,822,088)	(7,488,376)	(11,693,879)
totals	8760	4,009	8,889	28,090,240	61,451,994							11,119,519	26,332,480	13,537,511	29,615,521	18,962,171	41,482,852	(2,417,993)	(3,283,041)	(7,842,653)	(15,150,372)

Appendix 2-3 California Incremental NOx and CO_2 emission rates

A. <u>Edison</u>

Table D-1 Edison Emissions Summary – Flat Load Case

Year	Weight Factor	NOx	SOx	CO	PM10	ROG	CO2
LA AIRSHED							
		Incremental Emission Rates (lb/MWh)					
1998	0.4460	0.3611	0.0100	0.3401	0.0348	0.0839	1232.0
1999	0.4613	0.4853	0.0102	0.3806	0.0393	0.0854	1237.9
2000	0.5560	0.5291	0.0107	0.3899	0.0417	0.0844	1209.7
2001	0.5437	0.5068	0.0105	0.3739	0.0414	0.0810	1139.7
2002	0.5385	0.5982	0.0123	0.4063	0.0489	0.0848	1165.3
2003	0.5397	0.6422	0.0123	0.4071	0.0502	0.0846	1158.5
2004	0.5399	0.6876	0.0123	0.4086	0.0517	0.0843	1152.6
2005	0.5394	0.7349	0.0123	0.4106	0.0533	0.0844	1147.3
2006	0.5191	0.7283	0.0122	0.3977	0.0515	0.0831	1144.1
2007	0.4970	0.7234	0.0122	0.3838	0.0496	0.0822	1139.1
2008	0.4731	0.7199	0.0122	0.3681	0.0474	0.0813	1131.8
2009	0.4471	0.7187	0.0122	0.3504	0.0449	0.0807	1121.6
2010	0.4191	0.7197	0.0122	0.3301	0.0421	0.0801	1107.4
OTHER IN-STATE							
Year	**Factor**	**NOx**	**SOx**	**CO**	**PM10**	**ROG**	**CO2**
1998	0.2229	1.0482	0.0098	0.3323	0.0341	0.0129	1134.0
1999	0.2526	0.8081	0.0218	0.3706	0.0443	0.0246	1155.6
2000	0.1973	1.1578	0.0264	0.4328	0.0514	0.0322	1222.2
2001	0.2316	1.0484	0.0909	0.5850	0.0862	0.0683	1332.8
2002	0.2396	1.1884	0.1137	0.6552	0.1017	0.0854	1386.6
2003	0.2363	1.1821	0.1149	0.6679	0.1036	0.0874	1387.9
2004	0.2331	1.1766	0.1161	0.6806	0.1055	0.0895	1389.4
2005	0.2299	1.1709	0.1174	0.6942	0.1075	0.0915	1390.8
2006	0.2179	1.1925	0.1201	0.6798	0.1050	0.0881	1387.5
2007	0.2060	1.2143	0.1229	0.6620	0.1018	0.0842	1379.9
2008	0.1939	1.2361	0.1260	0.6401	0.0980	0.0795	1367.9
2009	0.1819	1.2579	0.1292	0.6117	0.0932	0.0741	1350.1
2010	0.1698	1.2808	0.1327	0.5769	0.0876	0.0676	1325.3
CALIFORNIA DESERT							
Year	**Factor**	**NOx**	**SOx**	**CO**	**PM10**	**ROG**	**CO2**
1998	0.0548	1.2739	0.0097	0.7025	0.0788	0.0794	1152.0
1999	0.0315	1.3037	0.0098	0.6883	0.0767	0.0804	1168.3
2000	0.0668	1.2358	0.0100	0.5695	0.0612	0.0809	1185.2
2001	0.0382	1.1039	0.0084	0.6731	0.0771	0.0687	993.8
2002	0.0290	1.1849	0.0093	0.5808	0.0638	0.0757	1103.2
2003	0.0269	1.1753	0.0091	0.5737	0.0630	0.0746	1087.0
2004	0.0248	1.1691	0.0090	0.5678	0.0624	0.0736	1072.3
2005	0.0227	1.1586	0.0088	0.5585	0.0614	0.0718	1051.1
2006	0.0219	1.1624	0.0089	0.5534	0.0607	0.0723	1058.1
2007	0.0211	1.1697	0.0090	0.5494	0.0600	0.0730	1068.4
2008	0.0203	1.1736	0.0090	0.5436	0.0591	0.0736	1076.0
2009	0.0195	1.1779	0.0091	0.5361	0.0581	0.0742	1083.9
2010	0.0187	1.1849	0.0092	0.5302	0.0572	0.0750	1095.4
OUT OF STATE							
Year	**Factor**	**NOx**	**SOx**	**CO**	**PM10**	**ROG**	**CO2**
1998	0.2763	4.2181	3.6810	0.3216	0.2598	0.0322	1789.4
1999	0.2547	4.3161	3.7604	0.3338	0.2608	0.0315	1896.1
2000	0.1798	4.4496	4.0446	0.3251	0.2738	0.0312	1903.1
2001	0.1864	4.3416	4.2595	0.3176	0.2699	0.0309	1896.6
2002	0.1930	4.5320	4.7568	0.3391	0.2987	0.0323	2000.0
2003	0.1978	4.5119	4.7103	0.3331	0.2987	0.0316	1961.4
2004	0.2028	4.4788	4.6695	0.3272	0.2983	0.0309	1923.4
2005	0.2080	4.4515	4.6211	0.3215	0.2976	0.0303	1886.5
2006	0.2453	4.4755	4.7425	0.3230	0.3071	0.0305	1898.2
2007	0.2823	4.5101	4.8549	0.3249	0.3159	0.0308	1912.7
2008	0.3192	4.5461	4.9586	0.3272	0.3242	0.0310	1928.0
2009	0.3559	4.5852	5.0598	0.3297	0.3324	0.0313	1945.0
2010	0.3924	4.6282	5.1605	0.3324	0.3404	0.0316	1962.6

C. PG&E

Table D-16 PG&E Emissions Summary -- Flat Load Case

LA AIRSHED

Year	Weight Factor	NOx	SOx	CO	PM10	ROG	CO2
		Incremental Emission Rates (lb/MWh)					
1998	0.3939	0.3388	0.0098	0.3365	0.0346	0.0829	1213.3
1999	0.4264	0.5100	0.0103	0.3675	0.0377	0.0865	1254.5
2000	0.4995	0.5807	0.0109	0.3990	0.0429	0.0866	1233.8
2001	0.4965	0.5667	0.0109	0.3897	0.0440	0.0835	1164.2
2002	0.4847	0.6820	0.0126	0.4107	0.0511	0.0860	1165.0
2003	0.4956	0.7048	0.0125	0.4131	0.0524	0.0857	1159.7
2004	0.5067	0.7266	0.0125	0.4156	0.0537	0.0851	1154.8
2005	0.5178	0.7480	0.0125	0.4182	0.0550	0.0849	1150.4
2006	0.4989	0.7413	0.0124	0.4039	0.0529	0.0835	1146.5
2007	0.4784	0.7360	0.0123	0.3883	0.0507	0.0825	1140.8
2008	0.4561	0.7322	0.0123	0.3705	0.0483	0.0816	1132.5
2009	0.4320	0.7304	0.0123	0.3508	0.0455	0.0808	1121.1
2010	0.4059	0.7309	0.0123	0.3279	0.0423	0.0801	1105.6

OTHER IN-STATE

Year	Factor	NOx	SOx	CO	PM10	ROG	CO2
1998	0.3156	0.9038	0.0099	0.3349	0.0339	0.0131	1135.1
1999	0.3191	0.6461	0.0161	0.3570	0.0414	0.0211	1141.4
2000	0.2790	1.2310	0.0203	0.4193	0.0466	0.0274	1204.4
2001	0.2943	1.0854	0.0857	0.5474	0.0798	0.0616	1303.3
2002	0.3040	1.2613	0.0926	0.6079	0.0898	0.0731	1338.1
2003	0.2893	1.2273	0.0976	0.6253	0.0931	0.0765	1346.0
2004	0.2744	1.1935	0.1032	0.6446	0.0968	0.0803	1354.9
2005	0.2595	1.1599	0.1096	0.6664	0.1009	0.0845	1364.2
2006	0.2441	1.1817	0.1123	0.6549	0.0989	0.0818	1363.3
2007	0.2288	1.2028	0.1152	0.6398	0.0963	0.0785	1357.9
2008	0.2134	1.2251	0.1183	0.6209	0.0930	0.0746	1348.0
2009	0.1979	1.2465	0.1218	0.5950	0.0890	0.0699	1331.6
2010	0.1824	1.2688	0.1256	0.5627	0.0839	0.0641	1307.5

CALIFORNIA DESERT

Year	Factor	NOx	SOx	CO	PM10	ROG	CO2
1998	0.0394	1.1444	0.0090	0.6197	0.0692	0.0736	1071.7
1999	0.0112	0.9985	0.0091	0.1810	0.0120	0.0715	1072.4
2000	0.0554	1.1680	0.0097	0.4782	0.0497	0.0787	1159.2
2001	0.0376	1.1839	0.0086	0.7723	0.0896	0.0710	1019.9
2002	0.0305	1.2020	0.0093	0.5896	0.0648	0.0759	1109.1
2003	0.0256	1.1932	0.0091	0.6040	0.0669	0.0744	1086.3
2004	0.0206	1.1822	0.0088	0.6262	0.0702	0.0725	1052.8
2005	0.0156	1.1667	0.0083	0.6643	0.0758	0.0688	998.2
2006	0.0163	1.1603	0.0085	0.6285	0.0710	0.0694	1013.4
2007	0.0170	1.1546	0.0086	0.5958	0.0666	0.0700	1028.1
2008	0.0177	1.1470	0.0087	0.5638	0.0623	0.0710	1038.8
2009	0.0184	1.1402	0.0088	0.5339	0.0583	0.0718	1049.4
2010	0.0191	1.1377	0.0089	0.5085	0.0549	0.0723	1063.2

OUT OF STATE

Year	Factor	NOx	SOx	CO	PM10	ROG	CO2
1998	0.2510	4.0743	3.7197	0.3070	0.2601	0.0306	1705.2
1999	0.2433	4.2090	3.7726	0.3204	0.2661	0.0301	1829.7
2000	0.1660	4.2496	3.9684	0.3029	0.2654	0.0291	1772.4
2001	0.1715	4.2533	4.3039	0.3073	0.2740	0.0294	1816.2
2002	0.1807	4.3520	4.6552	0.3233	0.2950	0.0303	1892.3
2003	0.1893	4.3650	4.6430	0.3198	0.2968	0.0301	1873.9
2004	0.1981	4.3609	4.6294	0.3162	0.2975	0.0298	1854.4
2005	0.2071	4.3611	4.6026	0.3126	0.2976	0.0296	1835.2
2006	0.2447	4.4076	4.7285	0.3163	0.3071	0.0300	1859.3
2007	0.2819	4.4556	4.8453	0.3199	0.3159	0.0304	1883.2
2008	0.3191	4.5048	4.9520	0.3234	0.3242	0.0307	1905.7
2009	0.3559	4.5590	5.0591	0.3271	0.3325	0.0311	1928.9
2010	0.3926	4.6089	5.1614	0.3308	0.3406	0.0314	1951.8

Appendix 2-4 Market Potential Methodology

Methodology: Industrial Market

The MIPD data was analyzed to produce a CHP potential of 4,480 MW. When we modify the low E/T ratio sites, defined as those with E/T ratios <0.4, to the electrical demand, rather than the steam site demand, the potential decreases to 1,863 MW, with 880MW coming from the E/T sites <0.4 and the rest coming from E/T >0.4 but <1.5. There were 3385 MW in sites with E/T ratios > 1.5. We assume that sites with E/T ratios above 0.4 have been sized to the electric load already, so that the total electric only MW for MIPD is equal to 3385 plus 1863, or 5248 MW. Sites with E/T ratios of <1.5 represent 35.5% of the total; those with E/T ratios >1.5 represent 64.5%.

If we were to extrapolate these characteristics to the entire population analyzed based on the CEC&EDD electric only data, 35.5% of the industrial megawatts would present characteristics favorable for combined heat and power. To derive total technical potential from the CEC&EDD data, it will be necessary to account for sizing the CEC MW that are <0.4 E/T to the steam load rather than the electric load. One starting assumption is that CEC sites which are larger than 250kW will exhibit similar thermal and electric characteristics to MIPD. The calculation is performed in aggregate, to reduce errors of SIC appropriation and other anomalies. Here is the entire procedure (see also the table to follow): Begin with CEC&EDD total MW, all sizes, all electric, all E/T; subtract self-generation; subtract MW at sites <250kW, giving the total electric utility generated consumption in MW for all CEC&EDD sites with capacities >250kW in size. Now take the MIPD electric only total potential, that is, for sites with <1.5 E/T ratios; to this number add the total MIPD MW for sites >1.5 E/T to get total electric only MW for MIPD; from this, subtract MIPD sites smaller than 250kW (if any) to get total electric utility generated consumption in MW for all MIPD for sites with capacities >250kW in size; now multiply by capacity factor to get average MW instead of peak MW. Next, subtract this number from the CEC&EDD MW total (from above). Then derive the percentage of all electric MW within the MIPD by dividing electric only MW by total MIPD MW <1.5 E/T. Multiply this number by the result of the previous step to get this gives the quantity of CEC&EDD MW that are all electric and <1.5 E/T. It is necessary to figure out how much of the CEC&EDD potential is <0.4 E/T, assuming again that its characteristics follow the E/T shape of MIPD. To do this we need a percentage of the <1.5 MW that are <0.4. Get this by dividing MIPD <0.4 by the total all electric MIPD MW <1.5. Multiply this percentage by the CEC&EDD MW to get the estimated CEC&EDD MW <0.4 E/T. Now it is desirable to find out how many MW of potential would this CEC&EDD <0.4E/T represent if it were sized to include both thermal and electric. To do this, we go again to MIPD to find out the ratio of electric only MW to electric plus thermal MW. Do this by dividing MIPD electric plus thermal by electric only. Now multiply this ratio by the CEC&EDD electric only MW to get CEC&EDD thermal plus electric MW. Now add in the CEC&EDD MW that are >0.4 E/T but <1.5 E/T; this will give total CEC&EDD MW that are < 1.5 E/T. Finally, add back the MIPD MW to get the total potential for the industrial sector.

Methodology: Commercial and Institutional Market

Electricity and gas consumption data was provided for a number of four digit activities in the State of California. The same methodology as above was used to estimate the average demand in each of these size bins. An approximate E/T ratio estimated from the total electric and gas consumption for each subsector can give an indication of thermal energy used, and therefore a rationale related to the soundness of CHP for this economic activity. The list of E/T ratios suggests that some activities may be less suitable than others in the C&I sectors. The grand total estimate is almost 9.2 GW of electric demand, over more than 230,000 sites (based on sales of natural gas and electricity). If we eliminate SIC 4941 (Water Treatment), and Supermarkets (SIC 54) our estimates are 6.983 MW for all sites. If we further subtract all commercial sites with electrical demands less than 50 kW, the site count drops to 26,815, with an average of just under 209 MW per site. We have matched the technical potential to the electric load only. Adjustments to steam loads would be warranted for those SIC activities which demonstrate a very low E/T ratio. With the elimination of these SICs, the total C&I potential can be calculated, without accounting for any increases due to large steam load matching**.** There are fewer than 111 sites in the C&I sector with estimated demands greater than 5 MW, which although understated, may make it less likely that electricity exports at high steam consumption sites are a significant figure. It is more likely that electrical site demand will drive sizing in C&I installations.

Uncertainties

The procedure for calculating the industrial sector market potential depends upon the extrapolation of data from MIPD to smaller industrial plants. It is possible that smaller plants do not have the same characteristics of internal proportion as larger ones within given industries, in which case apply the ratios for the larger plants to the smaller ones would lead to inaccuracies and over- or under-estimations of potential. This is true as well for assigning potential to SICs. Although the MIPD data should show valid absorption rates, when we assign the CEC MW to a particular sector, this is done based on the number of existing MW for the sector as a percentage of total MIPD MW. It could be that this additional potential is in another sector, as yet untapped by CHP. Thus, untapped potential markets for CHP may be misassigned within the sectors by this procedure

The calculation of E/T ratios for the commercial sector is by gas use, which may result in E/T values that are too low for those facilities that use gas for heating processes that cannot be replaced by CHP heat capture (such as cooking in restaurants, etc.) This uncertainty has been partially addressed by eliminating sectors with marginal (especially high) E/T ratios, to reduce the possibility of overstatement. The weighted average of E/T ratios for the selected commercial and institutional sectors is 1.18, quite low for commercial facilities. It should be pointed out too that no steam load matching has been done in these calculations, which means that the results presented here will be understated for those facilities with very low E/T ratios.

Both CEC and EDD data relied upon in this report contain roll-ups of certain SIC size categories, especially in larger sizes, due to issues of data confidentiality. For the commercial sector, where there was no reliable database of existing facilities, minimum electric capacities were assigned to these sites. This results in capacities that are understated for some commercial SICs.

	A	B	C	D	F	G	H	I	J	K	L	M	N	O	P
4		Calculation for extrapolating MIPD thermal characteristics to all electric CEC data to get industrial potential.													
5			elec		elec	elec	elec			elec	elec	Estimated	elec	elec	elec
6			all E/T		all E/T	all E/T	all E/T			all E/T	all E/T	Capacity	all E/T	all E/T	pot <1.5
7			all size	CEC	CEC less	<250kW	>250kW	MIPD elec	MIPD	all size	<250kW	Factor	>250kW	>250kW	>250kW
8	SIC	Sector	CEC MW	Self-Gen	Self-Gen	CEC MW	CEC MW	only <1.5	MW>1.5	MIPD MW	MIPD MW	pct %	MIPD MW	CEC - MIPD	MIPD %
9	20-39	All	8,441	544	7,897	1955.3	5,941.35	1863.1	3,385.40	5248.5	1.414	*68.00%*	3568.0	2373.3	35.5%
10															
11	20	Food Processing	969.97	34.65	935	155.54	779.78	500.93	332.74	833.67	0.666	*67.95%*	565.99	213.8	60.1%
12	22	Textile Mills	45.69	0.00	46	24.73	20.96	6.14	9.96	16.10	0	*73.15%*	11.77	9.2	38.1%
13	23	Apparel	180.9	0.00	181	151.01	29.89	1.31	13.54	14.85	0	*26.79%*	3.98	25.9	8.8%
14	24	Lumber & Wood	242.17	48.55	194	97.05	96.57	84.28	43.64	127.92	0	*51.06%*	65.32	31.3	65.9%
15	25	Furniture & Fixtures	116.81	0.00	117	56.22	60.59	11.95	38.39	50.34	0	*32.55%*	16.39	44.2	23.7%
16	26	Pulp & Paper	455.7	14.78	441	23.71	417.21	219.14	45.64	264.78	0.133	*78.43%*	207.57	209.6	82.8%
17	27	Printing & Publishing	178.55	0.27	178	127.93	50.35	6.29	35.20	41.48	0	*82.20%*	34.10	16.2	15.2%
18	28	Chemicals	523.42	64.55	459	124.77	334.10	130.66	270.23	400.89	0.269	*81.00%*	324.50	9.6	32.6%
19	29	Petroleum Products	883.02	360.09	523	9.98	512.95	638.41	250.24	888.65	0	*94.19%*	837.02	0.0	71.8%
20	30	Rubber & Misc. Plastics	361.02	0.00	361	99.24	261.78	30.20	118.67	148.87	0.346	*70.78%*	105.12	156.7	20.3%
21	31	Leather	7.43	0.00	7	7.43	0.00	0.66	1.12	1.78	0	*39.42%*	0.70	0.0	36.9%
22	32	Stone, Clay & Glass	473.42	1.00	472	73.23	399.19	29.49	334.88	364.36	0	*80.71%*	294.06	105.1	8.1%
23	33	Primary Metals	290.92	0.00	291	27.65	263.27	50.88	92.82	143.70	0	*65.63%*	94.31	169.0	35.4%
24	34	Fabricated Metals	404.67	0.68	404	243.47	160.52	26.41	127.10	153.51	0	*53.21%*	81.69	78.8	17.2%
25	35	Industrial Machinery	824.74	0.68	824	317.8	506.26	5.78	289.05	294.83	0	*40.27%*	118.74	387.5	2.0%
26	36	Electronics & Electric	1101.41	4.48	1,097	165.1	931.83	9.69	674.71	684.40	0	*56.43%*	386.21	545.6	1.4%
27	37	Transportation Equip.	708.26	12.51	696	89.56	606.19	102.17	403.15	505.32	0	*51.79%*	261.71	344.5	20.2%
28	38	Instruments & Products	517.72	0.00	518	112.97	404.75	7.35	276.31	283.66	0	*41.23%*	116.96	287.8	2.6%
29	39	Other Manufacturing	155.18	2.13	153	47.9	105.15	1.35	28.03	29.38	0	*42.40%*	12.46	92.7	4.6%
30															
31	Total		8441	544.363	7896.637	1955.29	5941.347	1863.0884	3385.4	5248.4914	1.414		3538.5761	2727.53537	

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD
4														
5	elec	elec	elec	elec	e+t		e + t	e + t	e + t		e + t		Apportion	
6	E/T<1.5	E/T<0.4	E/T<0.4	E/T <0.4	E/T <0.4	ratio	E/T <0.4	E/T >0.4<1.5	E/T < 1.5		E/T < 1.5	CEC+MIPD	Aggregate	**Total**
7	>250kW	>250kW	>250kW	>250kW	>250kW	t+e / e	>250kW	>250kW	>250kW	MIPD	> 250kW	SIC pct%	Total to each	**Mkt Potential**
8	CEC	MIPD MW	MIPD %ttl	CEC MW	MIPD MW	MIPD %	CEC	CEC	CEC	MW <1.5	CEC+MIPD	of Total	SIC -- MW	**by SIC -- MW**
9	842.5	880.1	47.2%	398.0	3497.3	3.97	1581.5	444.5	2026.0	4480.3	6506.3	n/a	n/a	**6506.3**
10		constant			constant					constant				
11	128.5	137.0	27.4%	35.1	573.21	4.18	147.0	93.3	240.3	937.1	1177.4	20.9%	422.9	**1,360.0**
12	3.5	3.1	50.3%	1.8	6.92	2.24	3.9	1.7	5.7	10.0	15.7	0.3%	5.6	**15.6**
13	2.3	0.0	0.0%	0.0	0.00	0.00	0.0	2.3	2.3	1.3	3.6	0.1%	1.3	**2.6**
14	20.6	73.9	87.7%	18.0	338.36	4.58	82.7	2.5	85.2	348.8	434.0	7.7%	155.9	**504.6**
15	10.5	0.9	7.3%	0.8	1.98	2.26	1.7	9.7	11.5	13.1	24.5	0.4%	8.8	**21.9**
16	173.5	144.7	66.0%	114.6	520.69	3.60	412.3	58.9	471.2	595.1	1066.3	18.9%	383.0	**978.2**
17	2.5	4.2	67.1%	1.7	9.29	2.20	3.6	0.8	4.4	11.4	15.8	0.3%	5.7	**17.0**
18	3.1	54.6	41.8%	1.3	454.99	8.33	10.9	1.8	12.7	531.0	543.7	9.6%	195.3	**726.3**
19	0.0	392.2	61.4%	0.0	1312.75	3.35	0.0	0.0	0.0	1558.9	1558.9	27.6%	560.0	**2,118.9**
20	31.8	8.4	27.7%	8.8	20.99	2.51	22.1	23.0	45.1	42.8	87.9	1.6%	31.6	**74.4**
21	0.0	0.7	100.0%	0.0	1.07	1.62	0.0	0.0	0.0	1.1	1.1	0.0%	0.4	**1.5**
22	8.5	20.9	71.0%	6.0	148.52	7.10	42.9	2.5	45.3	157.1	202.4	3.6%	72.7	**229.8**
23	59.8	7.0	13.7%	8.2	14.88	2.13	17.5	51.6	69.1	58.8	127.9	2.3%	45.9	**104.7**
24	13.6	14.3	54.2%	7.4	34.45	2.41	17.7	6.2	23.9	46.5	70.4	1.2%	25.3	**71.8**
25	7.6	1.0	16.6%	1.3	3.26	3.40	4.3	6.3	10.6	8.1	18.7	0.3%	6.7	**14.8**
26	7.7	4.9	50.7%	3.9	19.73	4.02	15.7	3.8	19.5	24.5	44.0	0.8%	15.8	**40.3**
27	69.7	10.9	10.7%	7.5	28.77	2.63	19.6	62.2	81.8	120.0	201.8	3.6%	72.5	**192.5**
28	7.5	0.0	0.0%	0.0	0.00	0.00	0.0	7.5	7.5	7.4	14.8	0.3%	5.3	**12.7**
29	4.3	1.4	100.0%	4.3	7.47	5.52	23.6	0.0	23.6	7.5	31.0	0.6%	11.1	**18.6**
30														
31	554.821	880.072		220.5753	3497.322		825.479	334.2455958	1159.725	4480.338	5640.1		2026.0	**6506.3**

Appendix 3-1 SCE and PG&E Rate Tariff Sheets

RATE SCHEDULE GS-2

Q Who should be on Schedule GS-2?

A Edison's Schedule GS-2 is designed primarily for its medium-sized commercial and industrial customers. These customers have electrical equipment which creates demands greater than 20 kilowatts but less than 500 kilowatts. Typical GS-2 customers include small manufacturing and processing firms as well as retail businesses, churches, service stations, schools, restaurants, and others.

THE BASIC CHARGES

GS-2 charges are discussed in detail below, but are basically separated into three categories:

- A monthly Customer Charge;
- An Energy Charge per kilowatthour (kWh) consumed;
- Demand Charges that apply to the highest demand registered (measured in kilowatts) within any 15 minute interval during a billing period.

GS-2 HAS A "BLOCKED-RATE" ENERGY CHARGE

Schedule GS-2 features a two-tiered energy charge known as a **blocked rate**. It works by charging one rate for the first block of kilowatthours used, and a lower rate for all the kilowatthours used after that, in the second block.

Edison is able to provide this lower rate because, after a certain point, some of its fixed costs are recovered and energy charges can be lowered to the level of the second tier to reflect lower costs. Yet **to reach the second tier, you must use 300 kWh for every 1 kW of demand that you register**. The table below shows an example of how this formula works.

AN EXAMPLE OF HOW THE GS-2 BLOCKED ENERGY CHARGE IS APPLIED

Demand registered in a billing period	25 kW
Number of kWh consumed in a billing period	10,000 kWh
Calculating the number of kWh in first block (normal rate)	25 kW x 300 kWh = 7,500 kWh
Calculating the number of kWh in second block (lower rate)	10,000 kWh - 7,500 kWh = 2,500 kWh
What appears on the bill	7,500 kWh billed at the normal rate 2,500 kWh billed at the lower rate

HOW A DEMAND CHARGE DIFFERS FROM AN ENERGY CHARGE

To understand the difference between energy and demand charges, imagine using ten 100-watt light bulbs. The moment the ten bulbs are turned on, they place a demand on the power system for 1,000 watts of electricity (10 bulbs x 100 watts each), or one kilowatt (kW). In this example, your electric meter would register 1 kW of demand.

If these light bulbs are left on for ten hours, they will consume 10,000 watthours of energy, or 10 kilowatthours (kWh). In this case, the electric meter would register 10 kWh of energy.

THE TIME RELATED DEMAND CHARGE

On Schedule GS-2, you are charged for two kinds of demand: Time Related and Facilities Related. The **Time Related Demand Charge** is applied only during Edison's summer season. It is meant to help recover part of Edison's higher costs of transmission and distribution in

This fact sheet is meant as an aid to understanding Edison's pricing options. It does not replace the tariffs. If there are differences between this material and the tariffs, the tariffs shall prevail.

summer months. It is a per kW charge applied to the greatest amount of demand created in each summer season month.

THE FACILITIES RELATED DEMAND CHARGE

The **Facilities Related Demand Charge** is also billed on a per kW basis, yet it is in effect each month of the year. It is applied to the greatest amount of demand created in the current month, *or* 50 percent of the highest demand created in the previous 11 months, whichever is more. This method of billing for demand is called a **ratchet**. By using this method the customer pays for the installed transmission and distribution facilities required to serve the customer's highest demand during the year.

SEASONS

The summer season begins the first Sunday in June and continues until the first Sunday in October of each year. The winter season is the rest of the year.

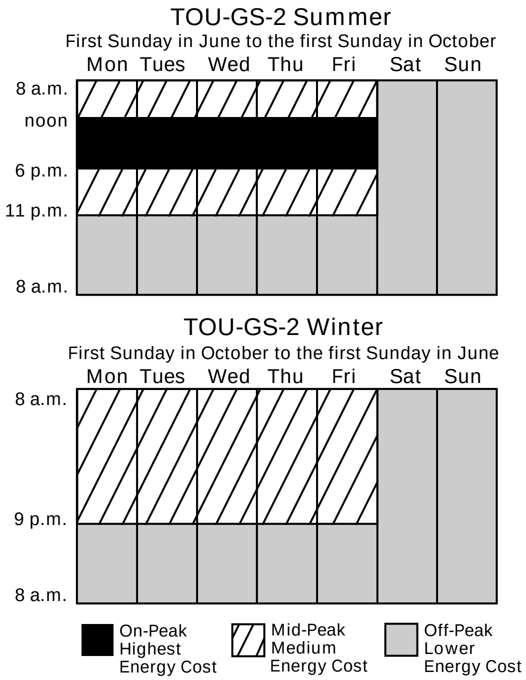
OTHER RATE OPTIONS

Customers who are eligible for GS-2 may also be eligible for other rate options that could help lower their electric bills. These include:

- **Time-of-use rate options**, which have differing demand and energy charges based on the time of day and season electricity is used. Charges during the on-peak period are significantly higher than other periods (see Schedule TOU-GS-2 at right). Customers who benefit from this rate have sufficient energy usage during the lower priced mid- and off-peak hours to offset the cost of the higher priced on-peak usage.

BECOMING ELIGIBLE FOR A NONDEMAND RATE SCHEDULE

If you register a demand of 20 kW or less for 12 consecutive months, you will be eligible to transfer to the nondemand GS-1 rate schedule.



Also, the 12-month requirement may be waived if you make changes in your operation that permanently reduce your demand below 20 kW. However, if your demand exceeds 20 kW within the first year, the rate change is rescinded and your account would be rebilled under the GS-2 rate.

PROCURING POWER FROM ANOTHER PROVIDER

Customers who choose to procure power (and possibly other services) from another provider will still be billed the GS-2 tariff charges noted above.

The difference will be that customers will also receive a credit on their bills for the cost of energy. This credit will be equal to the average cost of electricity at the California Power Exchange. In addition, customers will be accountable for paying any charges for electricity and other services that are levied by their Electric Service Provider.

WHERE TO CALL FOR MORE INFORMATION

If you have questions about Schedule GS-2, call **1-800-990-7788**, or talk to your Edison Sales Representative.

RATE SCHEDULE TOU-8

Q A

Who should be on Schedule TOU-8?

Schedule TOU-8 is the basic rate schedule for large-sized commercial and industrial customers who register demands greater than 500 kilowatts. These customers include large manufacturers and processors, supermarkets, and large office buildings.

THE BASIC CHARGES

TOU-8 charges are separated into three categories:

- A monthly Customer Charge;
- Energy Charges per kilowatthour consumed that vary by season and time of day;
- Demand Charges that also vary by season and time of day and apply to the highest demand (measured in kilowatts) within specific time periods.

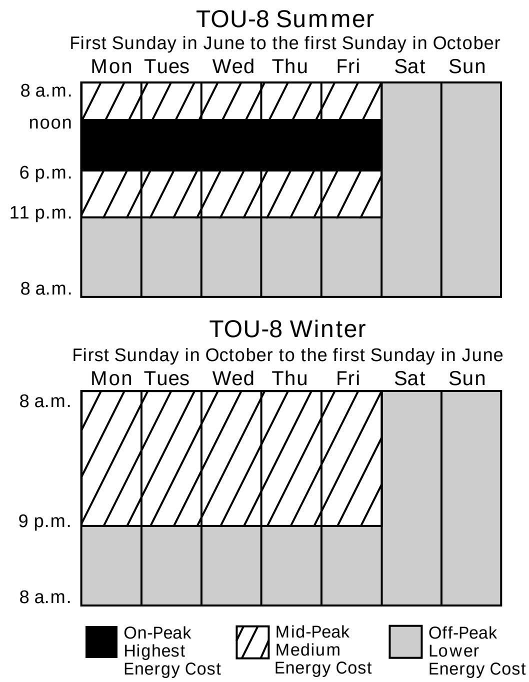
HOW A DEMAND CHARGE DIFFERS FROM AN ENERGY CHARGE

To understand the difference between energy and demand charges, imagine using ten 100-watt light bulbs. The moment the ten bulbs are turned on, they place a demand on the power system for 1,000 watts of electricity (10 bulbs x 100 watts each), or **one kilowatt (kW)**. In this example, your meter would register 1 kW of demand.

If these bulbs are left on for ten hours, they will consume 10,000 watthours of energy, or 10 **kilowatthours (kWh)**. In this case, your meter would register 10 kWh of energy.

THE TIME-OF-USE PERIODS

Time-of-use schedules such as TOU-8 are designed to correspond to Edison's costs based on the time of day and season service is being provided. The times are divided into three periods: **on-peak, mid-peak, and off-peak** (see illustration below). Energy and demand charges during the on-peak period are higher than charges in the mid-peak period and substantially higher than charges in the off-peak period.



SEASONS

The summer season begins the first Sunday in June and continues until the first Sunday in October of each year. The winter season is the rest of the year.

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THE TIME RELATED DEMAND CHARGE

On Schedule TOU-8, you are charged for two kinds of demand: Time Related and Facilities Related. The **Time Related Demand Charge** is applied only during Edison's summer season. It is a per kW charge for the greatest amount of demand created during the on- and mid-peak periods in each summer season month. It is meant to help recover part of Edison's higher costs of transmission and distribution in summer months.

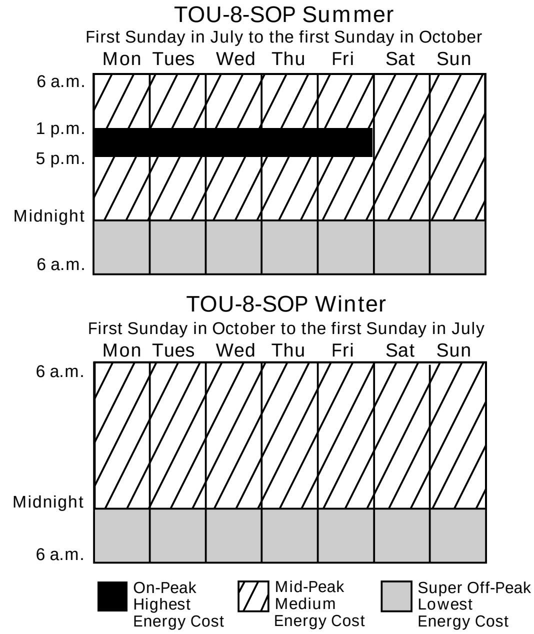
THE FACILITIES RELATED DEMAND CHARGE

The **Facilities Related Demand Charge** is also billed on a per kW basis, yet it is in effect each month of the year. It is applied to the greatest amount of demand created in the current month, *or* 50 percent of the highest demand created in the previous 11 months, whichever is more. This method of billing for demand is called a **ratchet**. By using this method the customer pays for the installed transmission and distribution facilities required to serve the customer's highest demand during the year.

OTHER RATE OPTIONS

Customers who are eligible for TOU-8 may also be eligible for other rate options that could help lower their electric bills. These include:

- **Interruptible rate options**, which provide lower energy and demand charges in exchange for complying with requests by Edison to interrupt power usage. These options are offered on a contract basis and are available only to existing customers who are adding new load and to customers new to SCE territory who have connected load of 50 horsepower or greater, or register a maximum demand of 50 kW or greater. There are substantial penalties for failing to interrupt when asked to do so.
- **Rate Schedule TOU-8-SOP**, which works like TOU-8 but features lower energy and demand charges for customers who use most or all of their energy during, or can move usage to, the **super-off-peak** time period (see illustrations below).



PROCURING POWER FROM ANOTHER PROVIDER

Customers who choose to procure power (and possibly other services) from another provider will still be billed the TOU-8 tariff charges noted above.

The difference will be that customers will also receive a credit on their bills for the cost of energy. This credit will be equal to the average cost of electricity at the California Power Exchange. In addition, customers will be accountable for paying any charges for electricity and other services that are levied by their Electric Service Provider.

WHERE TO CALL FOR MORE INFORMATION

If you have questions about Schedule TOU-8, call **1-800-990-7788**, or talk to your Edison Sales Representative.

This fact sheet is meant as an aid to understanding Edison's pricing options. It does not replace the tariffs. If there are differences between this material and the tariffs, the tariffs shall prevail.

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Schedule S

STANDBY

APPLICABILITY

Applicable to customers taking service under a regular service rate schedule and where a part or all of the electrical requirements of the customer can be supplied from a cogeneration or small power production source which meets the criteria for Qualifying Facility as defined under 18 CFR, Chapter 1, part 292, subpart B of the Federal Energy Regulatory Commission (FERC) regulations. The cogeneration or small power production source may be connected for: (1) parallel operation with the service of the Company; or (2) isolated operation with standby or breakdown service provided by the Company by means of a double-throw switch. This schedule is also applicable to standby or breakdown service where the entire electrical requirements on the customer's premises are not regularly supplied by the Company and the generation serving the customer is (1) not a Qualifying Facility, and (2) not in parallel with the service of the Company.

TERRITORY

Within the entire territory served.

RATES

	Service Voltage	Per Meter Per Month
Standby Charge:		
All kW of Standby Demand, per kW	Below 2 kV	$6.40
All kW of Standby Demand, per kW	2 kV to 50 kV	$6.60
All kW of Standby Demand, per kW	Above 50 kV	$0.65
Generation Reservation Charge (to be added to Standby Charge) Applicable to customers newly taking service under this schedule as of May 1, 1996:		
All kW of Standby Demand, per kW	Below 2 kV	$0.37
All kW of Standby Demand, per kW	2 kV to 50 kV	$0.36
All kW of Standby Demand, per kW	Above 50 kV	$0.35

Applicable Schedule Charges (to be added to Standby Charge and Generation Reservation Charge):

The Facilities Related Component of the Demand Charges designated in the applicable regular service rate schedule shall be applied to all kW of Facilities Related Billing Demand in the current month less Standby Demand but in no case applied to a difference less than zero. All other charges including any minimum charges and provisions of the applicable regular service rate schedule designated in the Generation Agreement or the Contract for Electric Service shall apply.

For customers served under this schedule whose regular service rate is Schedule TOU-8, the Standby and Generation Reservation Charges are excluded from the Peak Period and Average Rate Limiter calculation provided in Schedule TOU-8.

The rate components used for customer billing are determined using the components shown in the Rate Components Section following the Special Conditions Section.

(Continued)

SPECIAL CONDITIONS

1. Contract: A Contract is required for service under this schedule.

2. Generation Agreement: A Generation Agreement with the customer shall be required for service under this schedule where the cogeneration or small power production source is connected for parallel operation with the service of the Company.

3. Standby Demand: The level of standby demand shall be set forth in the Generation Agreement or Contract for Electric Service. The level of standby demand shall be determined by the Company and shall be the lower of (a) the nameplate capacity of the customer's generating facility; or (b) the Company's estimate of the customer's peak demand.

   The Company reserves the right to install, at the customer's expense, a demand meter to measure the customer's demand. The highest recorded demand shall be used to determine the customer's level of standby demand.

4. Allowance for Maintenance: After a customer has received service under this schedule for a period of six months, the added demand created by scheduled maintenance outages of the generating facility will be ignored for purposes of determining the Time Related Component of the demand charges under the applicable regular service rate schedule in months acceptable to the Company upon advance notice and subject to prevailing system peak conditions, subject to the conditions stated herein. Such conditions are that customer schedule and perform maintenance in accordance with the advance notice, outage duration, and outage frequency requirements set forth in the Generation Agreement, and following the period of scheduled maintenance, customer shows, to the satisfaction of the Company, what part of the recorded maximum demand utilized for billing in any of the months was added demand due to outage for such scheduled maintenance. This condition is applicable for one continuous outage per year of up to 30 consecutive days.

   The Company may, at its option, require that the customer defer scheduled maintenance. If scheduled maintenance is deferred, the Company will allow an outage for maintenance at a later date with allowance for maintenance in accordance herewith. Notice of such deferral, if required, shall be provided to the customer not less than 60 days prior to customer's scheduled outage date, except in the event of emergency. The Allowance for Maintenance applies only to customers served on a rate schedule which has a Time Related Component within the demand charge.

5. Excess Energy: For parallel connections, the customer may sell power to the Company under the terms of the Generation Agreement.

(Continued)

SPECIAL CONDITIONS (Continued)

6. Billing: A Customer's bill is first calculated according to the total rates and conditions above. The following adjustments are made depending on the option applicable to the customer.

   a. Bundled Service Customers receive supply and delivery services solely from Edison. The Customer's bill is based on the total rates set forth above. The Power Exchange (supply) component is equal to the Averaged Power Exchange (PX) Energy Charge as set forth in Schedule PX.

   b. Direct Access Customers purchase energy from an Energy Service Provider and continue receiving delivery services from Edison. The Averaged PX Energy Charge is determined as specified for a Bundled Service Customer. The customer's bill will be calculated as for a Bundled Service Customer, but the Customer will receive a credit for the Averaged PX Energy Charge. If the Averaged PX Energy Charge is greater than the amount of the Bundled Service bill, the minimum bill for a Direct Access Customer is zero.

   c. Hourly PX Pricing Option Customers receive supply and delivery services solely from Edison. A Customer taking Hourly PX Pricing Option service must have an interval meter installed at its premise to record hourly usage, since PX Energy Costs change hourly. If such metering is not currently installed, it shall be installed at the customer's expense before Hourly PX Pricing can be provided. Edison's charges for such metering are determined as set forth in Rule 2. The bill for a Hourly PX Pricing Option Customer is determined by calculating the bill as if it were for a Bundled Service Customer, then crediting the bill by the amount of the Averaged PX Energy Charge, as determined for Bundled Service and Direct Access Customers, then adding the hourly PX Energy Cost amount which is determined by multiplying the hourly energy used in the billing period by the hourly PX Energy Cost determined as set forth in Section 1 of Schedule PX, and the appropriate hourly Line Loss Adjustment Factors as set forth in Section 3 of Schedule PX, and the Uncollectibles expense factor of 1.00313.

7. Generation Charge: The generation charge is calculated based on the total rate less the sum of: Distribution, Transmission, Public Purpose Programs, Nuclear Decommissioning, and Fixed Transition Amount (where applicable) charges, the Transmission Revenue Balancing Account Adjustment (TRBAA), and the Public Utilities Commission Reimbursement Fee. The Competition Transition Charge (CTC) is calculated residually by subtracting the Averaged PX Energy Charge calculated as set forth in Schedule PX from the generation charge (See Rate Components Table).

8. Negotiating of CTC Payment Method: Nothing in this rate schedule prohibits a marketer or broker from negotiating with Customers the method by which their Customer will pay the CTC.

(Continued)

SPECIAL CONDITIONS (Continued)

9. Exemptions under Public Utilities Code, Section 380: "Eligible customers", as defined in Public Utilities (P.U.) Code Section 380, who operate a microgeneration facility are exempt from paying standby charges under this Schedule. An "eligible customer" is defined in P.U. Code Section 380 as a customer who has installed a microgeneration facility as defined in P.U. Code Section 331(f) on or after March 31, 1998 if that facility meets all of the following requirements:

   a. Is operated in parallel with SCE's transmission and distribution system,

   b. Is subject to SCE's Schedule S, Standby, and

   c. Is in full compliance with the best available control technology (BACT).

   A microgeneration facility is defined in P.U. Code Section 331(f) as "a cogeneration facility of less than one megawatt."

   Such exemptions shall not exceed a cumulative load of one megawatt (1MW) and shall expire on June 30, 2000.

(Continued)

RATE COMPONENTS

Rate Components Table

Rate Schedule Summary	Trans[1]	Distrbtn[2]	Gen[3,4]	NDC[5]	PPPC[6]	TRBAA[7]	PUCRF[8]	Total
Standby Charge - $/kW								
Below 2 kV	0.13	3.61	2.66					6.40
From 2 kV to 50 kV	0.13	3.74	2.73					6.60
Above 50 kV	0.15	0.24	0.26					0.65
Generation Reservation Charge - $/kW								
Below 2 kV	0.00	0.00	0.37					0.37
From 2 kV to 50 kV	0.00	0.00	0.36					0.36
Above 50 kV	0.00	0.00	0.35					0.35

1 Trans = Transmission
2 Distrbtn = Distribution
3 Gen = Generation
4 Competition Transition Charge (CTC) = Total Generation charge minus Averaged Power Exchange (PX) Energy Charge as set forth in Schedule PX..
5 NDC = Nuclear Decommissioning Charge
6 PPPC = Public Purpose Programs Charge (includes California Alternate Rates for Energy Surcharge and Discount where applicable.)
7 TRBAA = Transmission Revenue Balancing Account Adjustment
8 PUCRF = The PUC Reimbursement Fee is described in Schedule RF-E.
9 FTAC = The Fixed Transition Amount Charge is described in Schedule RRB.

SCHEDULE A-10—MEDIUM GENERAL DEMAND-METERED SERVICE

APPLICABILITY: A customer selecting service on Schedule A-10 after August 15, 1992 must use at least 50,000 kWh per year. Schedule A-10 applies to single-phase and polyphase alternating-current service (for a description of these terms, see Section D of Rule 2). This schedule is not available to customers whose maximum demand exceeds 499 kW for three consecutive months, or to residential or agricultural service for which a residential or agricultural schedule is applicable.

Under Schedule A-10, there is a limit on the demand (the number of kilowatts (kW)) the customer may require from the PG&E system. If the customer's demand exceeds 499 kW for three consecutive months, the customer's account will be transferred to Schedule E-19 or E-20.

The provisions of Schedule S—Standby Service Special Conditions 1 through 7 shall also apply to customers whose premises are regularly supplied in part (but not in whole) by electric energy from a nonutility source of supply. These customers will pay monthly reservation charges as specified under Section 1 of Schedule S in addition to all applicable Schedule A-10 charges.

TERRITORY: PG&E's entire service territory.

RATES

	Transmission	Distribution	Public Purpose Programs	Generation	Nuclear Decom-missioning	FTA	Total Rate
ENERGY CHARGE (per kWh per month)							
Transmission Voltage Level							
Summer	–	–	$0.00390	$0.07180 (I)	$0.00040	$0.01305(R)	$0.08915
Winter	–	–	$0.00390	$0.05544 (I)	$0.00040	$0.01305(R)	$0.07279
Primary Voltage Level							
Summer	–	$0.00508	$0.00345	$0.06713 (I)	$0.00044	$0.01305(R)	$0.08915
Winter	–	$0.00415	$0.00345	$0.05170 (I)	$0.00044	$0.01305(R)	$0.07279
Secondary Voltage Level							
Summer	–	$0.00785	$0.00359	$0.06420 (I)	$0.00046	$0.01305(R)	$0.08915
Winter	–	$0.00642	$0.00359	$0.04927 (I)	$0.00046	$0.01305(R)	$0.07279
DEMAND CHARGE (per kW of maximum demand per month)							
Transmission Voltage Level							
Summer	$0.91	–	–	$1.04	–	–	$1.95
Winter	$0.21	–	–	$0.24	–	–	$0.45
Primary Voltage Level							
Summer	$1.45	$4.05	–	–	–	–	$5.50
Winter	$0.44	$1.21	–	–	–	–	$1.65
Secondary Voltage Level							
Summer	$2.11	$4.59	–	–	–	–	$6.70
Winter	$0.52	$1.13	–	–	–	–	$1.65
CUSTOMER CHARGE, per meter per month	–	$75.00	–	–	–	–	$75.00
TRANSMISSION REVENUE BALANCING ACCOUNT ADJUSTMENT RATE per kWh per Month	($0.00017)	–	–	$0.00017	–	–	$0.00000

(Continued)

SCHEDULE A-10—MEDIUM GENERAL DEMAND-METERED SERVICE
(Continued)

RATES: (Cont'd.)

Generation charge is calculated based on the total rate less the sum of: Distribution, Transmission, Public Purpose Program, Nuclear Decommissioning, and FTA (where applicable) charges. CTC is calculated residually by subtracting the PX charge as calculated in Schedule PX from the generation charge. (N)

The above rate components apply to those customers eligible for the Rate Reduction Bond Credit. For those ineligible for the credit, the Generation component will be equal to the Generation component listed above plus the FTA component. (N)

BASIS FOR DEMAND CHARGE: The customer will be billed for demand according to the customer's "maximum demand" each month. The number of kW used will be recorded over 15-minute intervals; the highest 15-minute average in the month will be the customer's maximum demand. (L)

SPECIAL CASES: (1) If the customer's maximum demand has exceeded 400 kW for three consecutive months, 30-minute intervals will be used for averaging. The customer will be returned to 15-minute intervals when its maximum demand has dropped below 300 kW and remains there for 12 consecutive months. (2) If the customer's use of energy is intermittent or subject to violent fluctuations, a 5-minute or 15-minute interval may be used. (3) If the customer uses welders, the demand charge will be subject to the minimum demand charges for those welders' ratings, as explained in Section J of Rule 2. (L)

VOLTAGE DISCOUNTS: The customer may be eligible for a discount on the charges shown above if the customer takes delivery of electric energy at primary or transmission voltage. (L)

The voltage discount, if any, will be applied to the Demand Charge.

Discounts are applied in any month as follows:

(1) $1.20 per kW of maximum demand in the summer season (as defined below), and $0.00 per kW of maximum demand in the winter season when service is delivered from a "single customer substation" or without transformation from PG&E's serving distribution system at one of the standard primary voltages specified in PG&E's Electric Rule 2, Section B.1.

(2) $4.75 per kW of maximum demand in the summer season (as defined below), and $1.20 per kW of maximum demand in the winter season when service is without transformation from PG&E's serving transmission system at one of the standard transmission voltages specified in PG&E's Electric Rule 2, Section B.1.

PG&E retains the right to change its line voltage at any time. Customers receiving voltage discounts will get reasonable notice of any impending change. They will then have the option of taking service at the new voltage (and making whatever changes in their systems are necessary) or taking service without a voltage discount through transformers supplied by PG&E. (L)

(Continued)

SCHEDULE A-10—MEDIUM GENERAL DEMAND-METERED SERVICE
(Continued)

POWER FACTOR ADJUSTMENT: When the customer's maximum demand has exceeded 400 kW for three consecutive months and thereafter until it has fallen below 300 kW for 12 consecutive months, the bill will be adjusted for weighted monthly average power factor as follows: If the average power factor is greater than 85 percent, the total monthly bill (including any voltage adjustment but excluding any taxes) will be reduced by 0.06 percent for each percentage point above 85 percent. If the average power factor is below 85 percent, the total monthly bill (including any voltage adjustment but excluding any taxes) will be increased by 0.06 percent for each percentage point below 85 percent. Such average power factor will be computed (to the nearest whole percent) from the ratio of lagging reactive kilovolt ampere hours to kilowatt hours consumed in the month. No power factor correction will be made for any month when the customer's maximum demand is less than ten percent of the highest such demand in the preceding 11 months.

Power factor adjustments will be assigned to Generation for billing purposes. (N)

CONTRACT: For customers who use service for only part of the year, this schedule is available only on an annual contract.

SEASONS: The summer rate is applicable May 1 through October 31, and the winter rate is applicable November 1 through April 30. When billing includes use in both the summer and winter periods, demand and energy charges will be prorated based upon the number of days in each period.

(L)

(Continued)

SCHEDULE A-10—MEDIUM GENERAL DEMAND-METERED SERVICE
(Continued)

BILLING: A customer’s bill is first calculated according to the total rates and conditions above. The following adjustments are made depending on the option applicable to the customer. (N)

Bundled Service Customers receive supply and delivery services solely from PG&E. The customer’s bill is based on the Total Rate set forth above. The Power Exchange (supply) component is determined by multiplying the average Power Exchange cost for Schedule A-10 during the last month by the customer’s total usage.

Direct Access Customers purchase energy from an energy service provider and continue receiving delivery services from PG&E. The Power Exchange component is determined as specified for a Bundled Service Customer. The bill will be calculated as for a Bundled Service Customer, but the customer will receive a credit for the Power Exchange component. If the Power Exchange component is greater than the amount of the Bundled Service bill, the minimum bill for a Direct Access Customer is zero.

Hourly PX Pricing Option Customers receive supply and delivery services solely from PG&E. A customer taking Hourly PX Pricing Option service must have an interval meter installed at its premise to record hourly usage since Power Exchange costs change hourly. The bill for a Hourly PX Pricing Option Customer is determined by calculating the bill as if it were a Bundled Service Customer, then crediting the bill by the amount of the Power Exchange component, as determined for Bundled Service and Direct Access Customers, then adding the hourly Power Exchange component which is determined by multiplying the hourly energy used in the billing period by the hourly cost of energy from the Power Exchange.
(N)

(Continued)

SCHEDULE A-10—MEDIUM GENERAL DEMAND-METERED SERVICE
(Continued)

BILLING: (Cont'd.)

Nothing in this rate schedule prohibits a marketer or broker from negotiating with customers the method by which their customer will pay the CTC charge.

RATE REDUCTION BOND CREDIT:

Small commercial customers served on this schedule receive a 10 percent credit on their bill based on the total bill as calculated for Bundled Service Customers, by way of reduction to CTC. Only customers determined as eligible will receive the credit.

Additionally, customers eligible for the credit are obligated to pay a Fixed Transition Amount (FTA), also referred to as a Trust Transfer Amount (TTA), as described in Schedule E-RRB and defined in Preliminary Statement Part AS.

CARE DISCOUNT:

Facilities which meet the eligibility criteria in Rule 19.2 or 19.3 are eligible for a California Alternate Rates for Energy discount under Schedule E-CARE. Customers will continue to receive the CARE discount through PG&E regardless of energy service provider. Customers will be billed as described in the BILLING section; and the CARE discount will be determined before any credit for Direct Access service

BILLING FOR CUSTOMERS WITHOUT INTERVAL METERS:

All hourly PX pricing option customers and those direct access customers with interval meters will be billed as described in the Rates section above.

All bundled service customers and direct access customers without interval meters will be billed using the Total Rates listed in the Rates section above. Charges for each function will be determined by applying the following functional percentages to the total charge:

Transmission Voltage Level:

Transmission	Distribution	Public Purpose Programs	Generation	Nuclear Decommissioning
3.832% (I)	2.521%	3.576%	89.618% (R)	0.453%

Primary Voltage Level:

Transmission	Distribution	Public Purpose Programs	Generation	Nuclear Decommissioning
3.458% (I)	17.248%	3.576%	75.265% (R)	0.453%

Secondary Voltage Level:

Transmission	Distribution	Public Purpose Programs	Generation	Nuclear Decommissioning
4.488% (I)	21.501%	3.558%	70.000% (R)	0.453%

Generation charge is calculated based on the total charge less the sum of: Distribution, Transmission, Public Purpose Programs, and Nuclear Decommissioning. CTC is calculated residually by subtracting the Power Exchange component minus the amount of the FTA charge (if applicable) as set forth in the Rates section above.

COMMERCIAL/INDUSTRIAL/GENERAL

SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE

CONTENTS: This rate schedule is divided into the following sections:

1. APPLICABILITY: **Initial Assignment:** A customer is eligible for service under Schedule E-20 if the customer's maximum demand (as defined below) has exceeded 999 kilowatts for at least three consecutive months during the most recent 12-month period. If 70 percent or more of the customer's energy use is for agricultural end-uses, the customer will be served under an agricultural schedule.

Customer accounts which fail to qualify under these requirements will be evaluated for transfer to service under a different applicable rate schedule.

The provisions of Schedule S—Standby Service Special Conditions 1 through 7 shall also apply to customers whose premises are regularly supplied in part (but not in whole) by electric energy from a nonutility source of supply. These customers will pay monthly reservation charges as specified under Section 1 of Schedule S, in addition to all applicable Schedule E-20 charges.

Transfers Off of Schedule E-20: PG&E will review its Schedule E-20 accounts annually. A customer will be eligible for continued service on Schedule E-20 if its maximum demand has either: (1) Exceeded 999 kilowatts for at least 5 of the previous 12 billing months, or (2) Exceeded 999 kilowatts for any 3 consecutive billing months of the previous 14 billing months. If a customer's demand history fails both of these tests, PG&E will transfer that customer's account to service under a different applicable rate schedule, except as specified in the Energy Efficiency Adjustment provision below.

Assignment of New Customers: If a customer is new and PG&E believes that the customer's maximum demand will exceed 999 kilowatts and that the customer should not be served under a time-of-use agricultural schedule, PG&E will serve the customer's account under Schedule E-20.

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued)

1. APPLICABILITY: (Cont'd.)

Definition of Maximum Demand: Demand will be averaged over 30-minute intervals. "Maximum demand" will be the highest of all the 30-minute averages for the billing month. If the customer's use of electricity is intermittent or subject to violent fluctuations, a 5-minute or 15-minute interval may be used instead of the 30-minute interval. If the customer has any welding machines, the diversified resistance welder load, calculated in accordance with Section J of Rule 2, will be considered the maximum demand if it exceeds the maximum demand that results from averaging the demand over 30-minute intervals. The customer's maximum-peak-period demand will be the highest of all the 30-minute averages for the peak period during the billing month. (See Section 5 for a definition of "Peak-Period.") (L)

Standby Demand: For customers for whom Schedule S—Standby Service Special Conditions 1 through 7 apply, standby demand is the portion of a customer's maximum demand in any month caused by nonoperation of the customer's alternate source of power, and for which a demand charge is paid under the regular service schedule.

If the customer imposes standby demand in any month, then the regular service maximum demand charge will be reduced by the applicable reservation capacity charge (see Schedule S Special Condition 1).

To qualify for the above reduction in the maximum demand charge, the customer must, within 30 days of the regular meter-read date, demonstrate to the satisfaction of PG&E the amount of standby demand in any month. This may be done by submitting to PG&E a completed Electric Standby Service Log Sheet (Form 79-726).

Energy Efficiency Adjustment: A customer who implements measures to improve electrical energy efficiency on or after January 1, 1990, may be eligible to receive an energy efficiency adjustment. A customer will qualify for an energy efficiency adjustment if both following conditions are met: (1) the customer's service was established prior to January 1, 1990; and (2) the energy efficiency measures reduce the customer's maximum demand to the point that the customer would no longer be eligible for service under Schedule E-20.

To receive the energy efficiency adjustment, the customer must qualify for and sign an Agreement for Maximum Demand Adjustment for Energy Efficiency Measures (Form No. 79-758). The energy efficiency adjustment shall be the fixed reduction in demand specified in Form 79-758, and shall be added to the customer's maximum demand for the sole purpose of determining the customer's eligibility for Schedule E-20.

The energy efficiency adjustment specifically does not guarantee the customer's continued eligibility for service under Schedule E-20. The energy efficiency adjustment will not be applied to the customer's maximum demand for the purposes of calculating the monthly maximum demand charge.

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued)

2. TERRITORY: Schedule E-20 applies everywhere PG&E provides electricity service.

3. FIRM SERVICE RATES:

SECONDARY (E-20S)	Transmission	Distribution	Public Purpose Programs	Generation	Nuclear Decom-missioning	Total Rate
Maximum Peak-Period Demand						
Summer	$2.96 (R)	$4.63	–	$5.76 (I)	–	$13.35
Winter	–	–	–	–	–	–
Maximum Part-Peak-Period Demand						
Summer	$0.82 (R)	$1.28	–	$1.60 (I)	–	$3.70
Winter	$0.81 (R)	$1.27	–	$1.57 (I)	–	$3.65
Maximum Demand						
Summer	$0.57 (R)	$1.66	–	$0.32 (I)	–	$2.55
Winter	$0.57 (R)	$1.66	–	$0.32 (I)	–	$2.55
Energy Charges (per kWh)						
Peak-Period						
Summer	–	$0.01079	$0.00304	$0.07287	$0.00038	$0.08708
Winter	–	–	–	–	–	–
Part-Peak-Period						
Summer	–	$0.00715	$0.00304	$0.04710	$0.00038	$0.05767
Winter	–	$0.00786	$0.00304	$0.05216	$0.00038	$0.06344
Off-Peak-Period						
Summer	–	$0.00622	$0.00304	$0.04058	$0.00038	$0.05022
Winter	–	$0.00620	$0.00304	$0.04039	$0.00038	$0.05001
Economic Stimulus Rate Credit (per kWh)	–	–	–	$0.00432	–	$0.00432
Average Rate Limiter (per kWh in summer months)	–	–	–	–	–	$0.13995
Peak Period Rate Limiter (per kWh in summer months)	–	–	–	–	–	$0.97708
Customer Charge (per meter per month)	–	$385.00	–	–	–	$385.00
Transmission Revenue Balancing Account Adjustment Rate per kWh per month	($0.00017)	–	–	$0.00017	–	$0.00000

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued)

3. FIRM SERVICE RATES:
(Cont'd.)

PRIMARY (E-20P)	Transmission	Distribution	Public Purpose Programs	Generation	Nuclear Decom-missioning	Total Rate
Demand Charges (per kW)						
Maximum Peak-Period Demand						
Summer	$1.40 (R)	$2.79	–	$7.61 (I)	–	$11.80
Winter	–	–	–	–	–	–
Maximum Part-Peak-Period Demand						
Summer	$0.31 (R)	$0.63	–	$1.71 (I)	–	$2.65
Winter	$0.31 (R)	$0.63	–	$1.71 (I)	–	$2.65
Maximum Demand						
Summer	$0.30 (R)	$1.05	–	$1.20 (I)	–	$2.55
Winter	$0.30 (R)	$1.05	–	$1.20 (I)	–	$2.55
Energy Charges (per kWh)						
Peak-Period						
Summer	–	$0.00400	$0.00255	$0.05524	$0.00031	$0.06210
Winter	–	–	–	–	–	–
Part-Peak-Period						
Summer	–	$0.00310	$0.00255	$0.04225	$0.00031	$0.04821
Winter	–	$0.00362	$0.00255	$0.04976	$0.00031	$0.05624
Off-Peak-Period						
Summer	–	$0.00299	$0.00255	$0.04052	$0.00031	$0.04637
Winter	–	$0.00304	$0.00255	$0.04129	$0.00031	$0.04719
Economic Stimulus Rate Credit (per kWh)	–	–	–	$0.00432	–	$0.00432
Average Rate Limiter (per kWh in summer months)	–	–	–	–	–	$0.13995
Peak Period Rate Limiter (per kWh in summer months)	–	–	–	–	–	$0.84876
Customer Charge (per meter per month)	–	$310.00	–	–	–	$310.00
Transmission Revenue Balancing Account Adjustment Rate per kWh per month	($0.00017)	–	–	$0.00017	–	$0.00000

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued)

3. FIRM SERVICE RATES:
(Cont'd.)

TRANSMISSION (E-20T)	Transmission	Distribution	Public Purpose Programs	Generation	Nuclear Decom-missioning	Total Rate
Demand Charges (per kW)						
Maximum Peak-Period Demand						
Summer	$1.34 (R)	$0.21	–	$5.95 (I)	–	$7.50
Winter	–	–	–	–	–	–
Maximum Part-Peak-Period Demand						
Summer	$0.11	$0.02	–	$0.47	–	$0.60
Winter	$0.13 (R)	$0.02	–	$0.60 (I)	–	$0.75
Maximum Demand						
Summer	$0.06	$0.08	–	$0.21	–	$0.35
Winter	$0.06	$0.08	–	$0.21	–	$0.35
Energy Charges (per kWh)						
Peak-Period						
Summer	–	$0.00220	$0.00187	$0.05322	$0.00021	$0.05750
Winter	–	–	–	–	–	–
Part-Peak-Period						
Summer	–	$0.00167	$0.00187	$0.03986	$0.00021	$0.04361
Winter	–	$0.00205	$0.00187	$0.04956	$0.00021	$0.05369
Off-Peak-Period						
Summer	–	$0.00157	$0.00187	$0.03732	$0.00021	$0.04097
Winter	–	$0.00169	$0.00187	$0.04043	$0.00021	$0.04420
Economic Stimulus Rate Credit (per kWh)	–	–	–	$0.00432	–	$0.00432
Average Rate Limiter (per kWh in summer months)	–	–	–	–	–	–
Peak Period Rate Limiter (per kWh in summer months)	–	–	–	–	–	$0.55750
Customer Charge (per meter per month)	–	$715.00	–	–	–	$715.00
Transmission Revenue Balancing Account Adjustment Rate per kWh per month	($0.00017)	–	–	$0.00017	–	$0.00000

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued)

3. FIRM SERVICE RATES: (Cont'd.)

Generation charge is calculated based on the total rate less the sum of: Distribution, Transmission, Public Purpose Program, Nuclear Decommissioning, and FTA (where applicable) charges. CTC is calculated residually by subtracting the PX charge as calculated in Schedule PX from the generation charge. (N)

a. TYPES OF CHARGES: The customer's monthly charge for service under Schedule E-20 is the sum of a customer charge, demand charges, and energy charges: (L)

– The **energy charge** is the sum of the energy charges from the peak, partial-peak, and off-peak periods less the product of the Economic Stimulus Rate Credit and the total energy used during the billing month. The customer pays for energy by the kilowatt-hour (kWh), and rates are differentiated according to time of day and time of year.

– The monthly charges may be increased or decreased based upon the power factor. (See Section 6.)

– The **customer charge** is a flat monthly fee. (L)

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued)

3. FIRM SERVICE RATES: (Cont'd.)

a. TYPES OF CHARGES: (Cont'd.)

– Schedule E-20 has three **demand charges**, a maximum-peak-period-demand charge, a maximum-part-peak-period demand charge, and a maximum-demand charge. The maximum-peak-period-demand charge per kilowatt applies to the maximum demand during the month's peak hours, the maximum-part-peak-demand charge applies to the maximum demand during the month's part-peak hours, and the maximum-demand charge per kilowatt applies to the maximum demand at any time during the month. The bill will include all of these demand charges. (Time periods are defined in Section 5.) (L)

– As shown on the rate chart, which set of customer, demand, and energy charges is paid depends on the voltage at which service is taken. Service voltages are defined in Section 4 below.

– Please note that the rates in the chart on the preceding page apply only to firm service. Rates for non-firm service can be found in Section 12 of this rate schedule. Customers participating in the Nonfirm Bidding Pilot Program will be billed according to Section 17. Customers participating in the Local Nonfirm Bidding Pilot Program will be billed according to Section 18 (T)

b. AVERAGE RATE LIMITER (applies to firm service only): If the customer takes service on Schedule E-20, in either the secondary or primary voltage class, bills will be controlled by a "rate limiter" during the summer months. The bill will be reduced if necessary so that the average rate paid for all demand and energy charges during a summer month does not exceed the rate limiter shown on this schedule. This provision will not apply if the customer has elected to receive separate billing for back-up and maintenance service pursuant to Special Condition 8 of Schedule S.

Reductions in revenue resulting from application of the average rate limiter will be reflected as reduced generation amounts for billing purposes. (N)

c. PEAK-PERIOD RATE LIMITER (applies to firm service only): If the customer takes service on Schedule E-20 at any service voltage level, bills will be controlled by a "peak-period rate limiter" during the summer months. The bill will be reduced if necessary so that the average rate paid for all on-peak demand and energy charges during the peak period in a summer month does not exceed the peak-period rate limiter shown on this schedule. This provision will not apply if the customer has elected to receive separate billing for back-up and maintenance service pursuant to Special Condition 8 of Schedule S.

Reductions in revenue resulting from application of the peak-period rate limiter will be reflected as reduced generation amounts for billing purposes. (N)

(L)

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued)

4. DEFINITION OF SERVICE VOLTAGE: The following defines the three voltage classes of Schedule E-20 rates. Standard Service Voltages are listed in Rule 2. (L)

a. Secondary: This is the voltage class if the service voltage is less than 2,400 volts or if the definitions of "primary" and "transmission" do not apply to the service.

b. Primary: This is the voltage class if the customer is served from a "single customer substation" or without transformation from PG&E's serving distribution system at one of the standard primary voltages specified in PG&E's Electric Rule 2, Section B.1.

c. Transmission: This is the voltage class if the customer is served without transformation at one of the standard transmission voltages specified in PG&E's Electric Rule 2, Section B.1.

5. DEFINITION OF TIME PERIODS: Times of the year and times of the day are defined as follows:

SUMMER	Period A (Service from May 1 through October 31):	
Peak:	12:00 noon. to 6:00 p.m.	Monday through Friday (except holidays)
Partial-peak:	8:30 a.m. to 12:00 noon AND 6:00 p.m. to 9:30 p.m. Monday through Friday (except holidays).	
Off-peak:	9:30 p.m. to 8:30 a.m. All day	Monday through Friday Saturday, Sunday, and holidays (L)
WINTER	Period B (service from November 1 through April 30):	
Partial-Peak:	8:30 a.m. to 9:30 p.m.	Monday through Friday (except holidays).
Off-Peak:	9:30 p.m. to 8:30 a.m. All day	Monday through Friday (except holidays). Saturday, Sunday, and holidays

HOLIDAYS: "Holidays" for the purposes of this rate schedule are New Year's Day, President's Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas Day. The dates will be those on which the holidays are legally observed.

CHANGE FROM SUMMER TO WINTER OR WINTER TO SUMMER: When a billing month includes both summer and winter days, PG&E will calculate demand charges as follows. It will consider the applicable maximum demands for the summer and winter portions of the billing month separately, calculate a demand charge for each, and then apply the two according to the number of billing days each represents. NOTE: If the meter is read within one workday o the season changeover date (May 1 or November 1), PG&E will use only the rates and charges from the season having the greater number of days in the billing month. Workdays are Monday through Friday, inclusive.

(L)

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued)

6. POWER FACTOR ADJUSTMENTS: The bill will be adjusted based upon the power factor. The power factor is computed from the ratio of lagging reactive kilovolt-ampere-hours to the kilowatt-hours consumed in the month. Power factors are rounded to the nearest whole percent. (L)

The rates in this rate schedule are based on a power factor of 85 percent. If the average power factor is greater than 85 percent, the total monthly bill (excluding any taxes) will be reduced by 0.06 percent for each percentage point above 85 percent. If the average power factor is below 85 percent, the total monthly bill (excluding any taxes) will be increased by 0.06 percent for each percentage point below 85 percent. (L)

Power factor adjustments will be assigned to generation for billing purposes. (N)

7. CHARGES FOR TRANSFORMER AND LINE LOSSES: The demand and energy meter readings used in determining the charges will be adjusted to correct for transformation and line losses in accordance with Section B.4 of Rule 2. (L)

8. STANDARD SERVICE FACILITIES: If PG&E must install any new or additional facilities to provide the customer with service under Schedule E-20, the customer may have to pay some of the cost. Any advance necessary and any monthly charge for the facilities will be specified in a line extension agreement. See Rules 2, 15, and 16 for details.

Facilities installed to serve the customer may be removed when service is discontinued. The customer will then have to repay PG&E for all or some of its investment in the facilities. Terms and conditions for repayment will be set forth in the line extension agreement.

9. SPECIAL FACILITIES: PG&E will normally install only those standard facilities it deems necessary to provide service under Schedule E-20. If the customer requests any additional facilities, those facilities will be treated as "special facilities" in accordance with Section I of Rule 2. (L)

10. ARRANGEMENTS FOR VISUAL-DISPLAY METERING: If the customer wishes to have visual-display metering equipment in addition to the regular metering equipment, and the customer would like PG&E to install that equipment, the customer must submit a written request to PG&E. PG&E will provide and install the equipment within 180 days of receiving the request. The visual-display metering equipment will be installed near the present metering equipment. The customer will be responsible for providing the required space and associated wiring.

PG&E will continue to use the regular metering equipment for billing purposes.

(L)

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued)

11. NON-FIRM SERVICE PROGRAM: As noted, the rates in the chart in Section 3 of this rate schedule apply to firm service only. ("Firm" means service where PG&E provides a "continuous and sufficient supply of electricity," as described in Rule 14.) A customer may also elect to receive non-firm service under Schedule E-20. Customers participating in the Nonfirm Pilot Bidding Program should refer to Section 17. Customers participating in the Local Nonfirm Pilot Bidding Program should refer to Section 18.

The Non-firm Service Program is closed to existing customers as of January 1, 1993. However, if a new customer enters PG&E's service territory or an existing customer adds load at an existing premises after December 31, 1992, the customer may elect to participate in the Non-firm Service Program when (1) first taking service with PG&E (new customers) or (2) the additional load first is operational (existing customers). The new or existing customer's total load must meet the eligibility criteria in 11.a in order to participate in the Non-firm Service Program. Customers being served, as of December 31, 1992, under the Non-firm Service Program may continue to participate in the Non-firm Service Program.

Pursuant to the terms and conditions of the non-firm contract, PG&E hereby gives notice that on March 31, 2002, the current non-firm pricing incentive discount is terminated. The current level of non-firm pricing incentives is frozen through March 31, 2002, pursuant to Public Utilities Code Section 743.1 The California Public Utilities Commission has determined in PG&E’s Electric Rate Design Window proceeding (D.97-06-024) that PG&E's non-firm customers should be made aware that at the conclusion of the statutory period the current non-firm pricing incentive will be terminated.

After March 31, 2002, non-firm pricing incentives are likely to be based primarily on market conditions and can be expected to changed significantly. This notice is not intended to give non-firm customers the impression that non-firm service will be of no value after March 31, 2002. Instead, this notice is intended to make clear that after March 31, 2002, the value of non-firm service will likely be evaluated based on market principles, and will most likely differ from non-firm incentives in effect at present.

A customer who elects to receive non-firm service under Schedule E-20 must participate in PG&E's Emergency Curtailment Program. A non-firm service customer may also elect to participate in PG&E's Underfrequency Relay (UFR) Program. (T)

– EMERGENCY CURTAILMENT PROGRAM: Under the Emergency Curtailment Program, a non-firm service customer may be required to reduce demand to a designated number of kilowatts (kW), referred to as the customer's contractual "firm service level." PG&E will make requests for such curtailments from its non-firm service customers upon notification from the California Independent System Operator (ISO) that a systemwide or local operating condition exists which will impair the ability of the ISO to meet the demands of PG&E’s other customers. The ISO is expected to issue load curtailment directives to PG&E in those instances where load reductions are necessary in order to maintain systemwide operating reserves above the 5 percent level throughout the next operating hour, or if such load reductions are the sole remaining measure available in order to mitigate transmission overloads in the PG&E area. (T)

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued)

11. NON-FIRM SERVICE PROGRAM: (Cont'd.)

– UNDERFREQUENCY RELAY PROGRAM: Under this program, the customer agrees to be subject at all times to automatic interruptions of service caused by an underfrequency relay device that may be installed by PG&E.

(D)
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(D)

See Section 13 of this rate schedule below of this rate schedule for a discussion of contractual length-of-service requirements that may be applied to customers enrolling in the Non-firm Service Program. Please note that PG&E may require up to three years' written notice for a change from non-firm to firm service, or for termination of participation in the Underfrequency Relay Program. (T)

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued)

11. NON-FIRM SERVICE PROGRAM: (Cont'd.)

a. ELIGIBILITY CRITERIA FOR NON-FIRM SERVICE: To qualify for non-firm service, the customer must have had an average peak-period demand of at least 500 kW during each of the last six summer billing months prior to the customer's application for non-firm service. (Average peak-period demand is the total number of kWh used during the peak-period hours of a billing month divided by the total number of peak-period hours in the month.) Customers who have not yet had six months of summer service must demonstrate to PG&E's satisfaction that they will maintain an average monthly-peak-period demand of 500 kW or more to qualify for non-firm service.

b. DESIGNATION OF FIRM SERVICE LEVEL: If a customer takes non-firm service, the designated number of kW to which the customer must reduce demand during emergency curtailments is the customer's contractual "firm service level." This designated firm service level must be at least 500 kW less than the smallest of the customer's average peak-period demands during the last six summer billing months prior to the designation.

c. PRE-EMERGENCY CURTAILMENT REQUIREMENTS: A customer may be requested to curtail, on a pre-emergency basis, up to five times per year. Each pre-emergency curtailment will last no more than five hours. Customers will be given at least 30 minutes notice before each curtailment. PG&E will request at least six pre-emergency curtailments during any rolling three-year period. The pre-emergency curtailments will be requested subject to the criteria listed in Section 11.d below.

No pre-emergency curtailments will be called before May 3, 1993.

Customers participating in the Under-Frequency Relay (UFR) Program will be subject to a maximum of three pre-emergency curtailments per year and to at least three pre-emergency curtailments during any rolling three-year period. Automatic UFR operations shall not be included in the annual pre-emergency or emergency curtailment limit.

No pre-emergency curtailments will be called for any non-firm customer if there have been two or more emergency or pre-emergency curtailments to date during the year; unless additional pre-emergency curtailments are necessary to meet the minimum requirement of six pre-emergency curtailments during a rolling three-year period.

d. PRE-EMERGENCY CURTAILMENT PROCEDURE: PG&E will notify the customer by telephone, electronic mail, or other reliable means of communication. This notification will designate the time by which the customer's kW demand must be reduced to the customer's contractual firm service level. The notification will also designate the time when the customer may resume use of full power.

PG&E may call a pre-emergency curtailment if one of the following criteria are met:

1) The 9:00 a.m. forecast of temperatures in the Central Valley (the average of the forecasted temperature in Fresno and Sacramento) exceeds 100 degrees Fahrenheit; and PG&E has been informed by the ISO that an adjusted 10:00 a.m. forecast of two-hour reserves for that afternoon's peak is 12 percent or less; or (T)
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(T)

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued) (L)

11. NON-FIRM SERVICE PROGRAMS: (Cont'd.)

d. PRE-EMERGENCY CURTAILMENT PROCEDURE: (Cont'd.)

2) The 9:00 a.m. forecast of temperatures in the Central Valley exceeds 105 degrees F; or

e. EMERGENCY CURTAILMENT PROCEDURE: When it becomes necessary for PG&E to request a curtailment, PG&E will notify the customer by telephone, electronic mail, or other reliable means of communication. This notification will designate a time by which the customer's kW demand must be reduced to the customer's contractual firm service level.

The customer may not resume the use of curtailed power until notified by PG&E that it may do so or until the customer has curtailed its service for six hours.

f. LIMIT ON EMERGENCY CURTAILMENTS: A customer will be requested to curtail demand, under the emergency curtailment program, no more than 30 times per year and will be given at least 30 minutes notice before each curtailment. Curtailments will not exceed six hours for any individual interruption or 100 hours for the entire year.

g. EMERGENCY-NOTICE PROVISION: If there is an emergency on the PG&E system, PG&E may ask the customer to curtail the use of electricity on less than the 30 minute notice allowed for the Non-Firm Service Option. The customer will be asked to make its best effort to comply. The customer will not be assessed the noncompliance penalty for failing to comply within the shorter notice period, but the customer will be assessed this penalty if the regular notice period for the option passes and the customer still has not curtailed use.

h. NONCOMPLIANCE PENALTY: If PG&E requests that a non-firm service customer curtail the use of electricity and the customer fails to do so by the time specified, the customer must pay a noncompliance penalty. This penalty will be payable in addition to the regular charges. (L)

The penalty will be calculated by determining the total amount of excess energy taken during the curtailment period (energy taken in excess of the customer's firm service level times the duration of the curtailment) and multiplying this total by the noncompliance penalty (per kWh). (L)

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued)

11. NON-FIRM SERVICE PROGRAMS: (Cont'd.)

d. PRE-EMERGENCY CURTAILMENT PROCEDURE: (Cont'd.)

2) The 9:00 a.m. forecast of temperatures in the Central Valley exceeds 105 degrees F; or

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(D)

e. EMERGENCY CURTAILMENT PROCEDURE: When it becomes necessary for PG&E to request a curtailment, PG&E will notify the customer by telephone, electronic mail, or other reliable means of communication. This notification will designate a time by which the customer's kW demand must be reduced to the customer's contractual firm service level.

The customer may not resume the use of curtailed power until notified by PG&E that it may do so or until the customer has curtailed its service for six hours.

f. LIMIT ON EMERGENCY CURTAILMENTS: A customer will be requested to curtail demand, under the emergency curtailment program, no more than 30 times per year and will be given at least 30 minutes notice before each curtailment. Curtailments will not exceed six hours for any individual interruption or 100 hours for the entire year.

g. EMERGENCY-NOTICE PROVISION: If there is an emergency on the PG&E system, PG&E may ask the customer to curtail the use of electricity on less than the 30 minute notice allowed for the Non-Firm Service Option. The customer will be asked to make its best effort to comply. The customer will not be assessed the noncompliance penalty for failing to comply within the shorter notice period, but the customer will be assessed this penalty if the regular notice period for the option passes and the customer still has not curtailed use.

h. NONCOMPLIANCE PENALTY: If PG&E requests that a non-firm service customer curtail the use of electricity and the customer fails to do so by the time specified, the customer must pay a noncompliance penalty. This penalty will be payable in addition to the regular charges.

The penalty will be calculated by determining the total amount of excess energy taken during the curtailment period (energy taken in excess of the customer's firm service level times the duration of the curtailment) and multiplying this total by the noncompliance penalty (per kWh).

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COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued)

11. NON-FIRM SERVICE PROGRAM: (Cont'd.)

i. ADDITIONAL NON-FIRM SERVICE PROVISIONS:

1) **Required Re-Designations of Firm Service Level**: A non-firm service customer must maintain a difference of at least 500 kW between the firm service level and the average monthly summer peak-period demand. If the difference is less than 500 kW for any three summer months during any 12-month period, the customer must designate a new firm service level. This new firm service level must be at least 500 kW below the lowest of the customer's average peak-period demands for the last six summer billing months preceding the new designation. If the customer cannot meet this requirement, PG&E will change the account to firm service.

2) **Optional Re-Designations of Firm Service Level**: A non-firm service customer may decrease the firm service level effective with the start of any billing month, provided the customer gives PG&E at least 30 days' written notice. The customer may increase the firm service level (or return to full service) only with PG&E's permission or by giving PG&E three years notice, or by giving such notice to PG&E during a one-month period following any revisions of the program operating criteria initiated by the ISO, or during an annual contract review period that is provided for between November 1 and December 1 each year. The increased firm service level must be such that there is still at least a 500-kW difference between the firm service level and the lowest average monthly summer peak-period demand. The increased firm service level will become effective with the first regular reading of the meter after the customer receives permission from PG&E or at the end of the three year notice period. If a customer elects to change to firm service, they will not be permitted to subsequently return to non-firm status in the future. (T)

3) **Telephone Line Requirements**: Non-firm customers are required to make available a telephone line and space for a notification printer.
This requirement is in addition to any other equipment requirement which may apply.

j. BILL REDUCTIONS FOR NON-FIRM SERVICE CUSTOMERS:

1) **Demand Charges**: Reduced peak-period demand charges for curtailable service shall be applied to the difference between the customer's maximum demand in the peak-period and its Firm Service Level (but not less than zero). The peak-period charges for firm service shall be applied to the peak-period demand less the above difference.

2) **Energy Charges**: Reduced energy charges for curtailable service shall be applied to (a-b), where (a) is the number of kilowatt-hours used in the time period and (b) is the product of the Firm Service Level and the number of hours in the time period. (a-b) shall not be less than zero.

3) **Economic Stimulus Rate Credit**: The energy charges described in 11.j.2 shall be reduced by the product of the Economic Stimulus Rate Credit and (a-b) as calculated in 11.j.2.

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued)

11. NON-FIRM SERVICE PROGRAM: (Cont'd.)

k. PROVISIONS SPECIFIC TO UFR PROGRAM:

1) **Details on Automatic Interruptions**: If a customer is participating in the UFR program, service to the customer will be automatically interrupted if the frequency on the PG&E system drops to 59.65 hertz for 20 cycles. PG&E will install and maintain a digital underfrequency relay and whatever associated equipment it believes is necessary to carry out such automatic interruption. Relays and other equipment will remain the property of PG&E. If more than one relay is required, PG&E will provide the additional relays as "special facilities," at customer's expense, in accordance with Section I of Rule 2.

   In addition to the underfrequency relay, PG&E may install equipment that would automatically interrupt service in case of voltage reductions or other operating conditions.

2) **Metering Requirements for UFR Program**: If a customer is participating in the UFR program under Schedule E-20 in combination with firm or curtailable-only service, the customer will be required to have a separate meter for the UFR service. PG&E will provide the meter sets, but the customer will be responsible for arranging customer's wiring in such a way that the service for each account can be provided and metered at a single point. NOTE: Any other additional facilities required for a combination of curtailable with firm service will be treated as "special facilities" in accordance with Section I of Rule 2.

3) **Communication Channel for UFR Service**: UFR program customers are required to provide an exclusive communication channel from the PG&E-provided terminal block at the customer's facility to a PG&E-designated control center. The communication channel must meet PG&E's specifications, and must be provided at the customer's expense. PG&E shall have the right to inspect the communication circuit upon reasonable notice.

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20–SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued)

12. NON-FIRM SERVICE RATES: These rates are applicable if the customer elects to take non-firm service. See Section 11 for an explanation of the non-firm service program and elegibility criteria.

SECONDARY (E-20S)	Transmission	Distribution	Public Purpose Programs	Generation	Nuclear Decom-missioning	Total Rate
Demand Charges (per kW)						
Maximum Peak-Period Demand						
Summer	$2.96 (R)	$4.63	–	($1.74) (I)	–	$5.85
Winter	–	–	–	–	–	–
Maximum Part-Peak-Period Demand						
Summer	$0.82 (R)	$1.28	–	$1.10 (I)	–	$3.20
Winter	$0.81 (R)	$1.27	–	$1.07 (I)	–	$3.15
Maximum Demand						
Summer	$0.57 (R)	$1.66	–	$0.32 (I)	–	$2.55
Winter	$0.57 (R)	$1.66	–	$0.32 (I)	–	$2.55
Energy Charges (per kWh)						
Peak-Period						
Summer	–	$0.01079	$0.00304	$0.06040	$0.00038	$0.07461
Winter	–	–	–	–	–	–
Part-Peak-Period						
Summer	–	$0.00715	$0.00304	$0.04578	$0.00038	$0.05635
Winter	–	$0.00786	$0.00304	$0.05084	$0.00038	$0.06212
Off-Peak-Period						
Summer	–	$0.00622	$0.00304	$0.03926	$0.00038	$0.04890
Winter	–	$0.00620	$0.00304	$0.03907	$0.00038	$0.04869
Economic Stimulus Rate Credit (per kWh)	–	–	–	$0.00432	–	$0.00432
UFR Credit (per kWh) (if applicable)	–	–	–	$0.00091	–	$0.00091
Noncompliance Penalty (per kWh per event)	–	–	–	$8.40	–	$8.40
Noncompliance Penalty For customers who fully complied with the previous year's operations (per kWh per event)	–	–	–	$4.20	–	$4.20
Nonfirm Customer Charge (per meter per month)	–	$385.00	–	$190.00	–	$575.00
Nonfirm with UFR Customer Charge (per meter per month)	–	$385.00	–	$200.00	–	$585.00
Transmission Revenue Balancing Account Adjustment Rate per kWh per month	($0.00017)	–	–	$0.00017	–	$0.00000

* See Section 11 for the application of Noncompliance Penalties. The reduced Noncompliance Penalties are not available for 1992.

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COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued)

12. NON-FIRM SERVICE RATES: (Cont'd.)

PRIMARY (E-20P)	Transmission	Distribution	Public Purpose Programs	Generation	Nuclear Decom-missioning	Total Rate
Demand Charges (per kW)						
Maximum Peak-Period Demand						
Summer	$1.40 (R)	$2.79	–	$0.11 (I)	–	$4.30
Winter	–	–	–	–	–	–
Maximum Part-Peak-Period Demand						
Summer	$0.31 (R)	$0.63	–	$1.21 (I)	–	$2.15
Winter	$0.31 (R)	$0.63	–	$1.21 (I)	–	$2.15
Maximum Demand						
Summer	$0.30 (R)	$1.05	–	$1.20 (I)	–	$2.55
Winter	$0.30 (R)	$1.05	–	$1.20 (I)	–	$2.55
Energy Charges (per kWh)						
Peak-Period						
Summer	–	$0.00400	$0.00255	$0.04277	$0.00031	$0.04963
Winter	–	–	–	–	–	–
Part-Peak-Period						
Summer	–	$0.00310	$0.00255	$0.04093	$0.00031	$0.04689
Winter	–	$0.00362	$0.00255	$0.04844	$0.00031	$0.05492
Off-Peak-Period						
Summer	–	$0.00299	$0.00255	$0.03920	$0.00031	$0.04505
Winter	–	$0.00304	$0.00255	$0.03997	$0.00031	$0.04587
Economic Stimulus Rate Credit (per kWh)	–	–	–	$0.00432	–	$0.00432
UFR Credit (per kWh) (if applicable)	–	–	–	$0.00091	–	$0.00091
Noncompliance Penalty (per kWh per event)	–	–	–	$8.40	–	$8.40
Noncompliance Penalty For customers who fully complied with the previous year's operations (per kWh per event)	–	–	–	$4.20	–	$4.20
Nonfirm Customer Charge (per meter per month)	–	$310.00	–	$190.00	–	$500.00
Nonfirm with UFR Customer Charge (per meter per month)	–	$310.00	–	$200.00	–	$510.00
Transmission Revenue Balancing Account Adjustment Rate per kWh per month	($0.00017)	–	–	$0.00017	–	$0.00000

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued)

12. NON-FIRM SERVICE RATES: (Cont'd.)

TRANSMISSION (E-20T)	Transmission	Distribution	Public Purpose Programs	Generation	Nuclear Decom-missioning	Total Rate
Demand Charges (per kW)						
Maximum Peak-Period Demand						
Summer	$1.34 (R)	$0.21	–	($1.55) (I)	–	$0.00
Winter	–	–	–	–	–	–
Maximum Part-Peak-Period Demand						
Summer	$0.11	$0.02	–	($0.03)	–	$0.10
Winter	$0.13 (R)	$0.02	–	$0.10 (I)	–	$0.25
Maximum Demand						
Summer	$0.06	$0.08	–	$0.21	–	$0.35
Winter	$0.06	$0.08	–	$0.21	–	$0.35
Energy Charges (per kWh)						
Peak-Period						
Summer	–	$0.00220	$0.00187	$0.04075	$0.00021	$0.04503
Winter	–	–	–	–	–	–
Part-Peak-Period						
Summer	–	$0.00167	$0.00187	$0.03854	$0.00021	$0.04229
Winter	–	$0.00205	$0.00187	$0.04824	$0.00021	$0.05237
Off-Peak-Period						
Summer	–	$0.00157	$0.00187	$0.03600	$0.00021	$0.03965
Winter	–	$0.00169	$0.00187	$0.03911	$0.00021	$0.04288
Economic Stimulus Rate Credit (per kWh)	–	–	–	$0.00432	–	$0.00432
UFR Credit (per kWh) (if applicable)	–	–	–	$0.00091	–	$0.00091
Noncompliance Penalty (per kWh per event)	–	–	–	$8.40	–	$8.40
Noncompliance Penalty For customers who fully complied with the previous year's operations (per kWh per event)	–	–	–	$4.20	–	$4.20
Nonfirm Customer Charge (per meter per month)	–	$715.00	–	$190.00	–	$905.00
Nonfirm with UFR Customer Charge (per meter per month)	–	$715.00	–	$200.00	–	$915.00
Transmission Revenue Balancing Account Adjustment Rate per kWh per month	($0.00017)	–	–	$0.00017	–	$0.00000

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued)

12. NON-FIRM SERVICE RATES: (Cont'd.)

Generation charge is calculated based on the total rate less the sum of: Distribution, Transmission, Public Purpose Program, Nuclear Decommissioning, and FTA (where applicable) charges. CTC is calculated residually by subtracting the PX charge as calculated in Schedule PX from the generation charge.

13. CONTRACTS:

a. STANDARD SERVICE AGREEMENT: To begin service under Schedule E-20, the customer shall be required to sign PG&E's Electric General Service Agreement (GSA). The GSA has an initial term of three (3) years. Once the three-year initial term is over, the agreement will automatically continue in effect for successive terms of one year each until it is cancelled. Customers may, at any time, request PG&E to modify the GSA if the service arrangements, electrical demand requirements, or delivery criteria to its premises change. However, customers will still be obligated to perform the terms and conditions outlined in any other agreements that supplement the GSA. (T)

Customer load shall only be served under only one of PG&E's discount agreements. These agreements include, but are not limited to, PG&E's non-firm service agreement and the long term service options described below. Customers requesting service under any of these discount agreements shall be required to sign a supplemental agreement to the GSA.

b. LONG-TERM SERVICE AGREEMENT OPTIONS: Certain customers who would prefer to contract with PG&E for the supply and delivery of electricity into the future may qualify for a long term service agreement with PG&E. These agreements will supplement and be made part of the GSA. Long term service agreements are intended to attract or retain efficient electric load to PG&E's service territory, and were approved in Decision 95-10-033.

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued)

13. CONTRACTS: (Cont'd.)

b. LONG-TERM SERVICE AGREEMENT OPTIONS: (Cont'd.) (T)

PG&E shall not be permitted to enter into any long-term service agreements after June 1, 1999, or after elimination of the Electric Revenue Adjustment Mechanism (ERAM) and/or the effective date of a decision establishing Performance Base Ratemaking for the electric operations of PG&E, whichever occurs first. Any long-term service agreements entered into by PG&E prior to the end of eligibility for these contracts will be carried out to their completion dates or termination, whichever occurs first.

Customers may qualify for one of three long term agreements:

- Agreement for Attracting Manufacturing Business and Electric Load
- Agreement for the Expansion and Retention of Incremental Electric Load
- Agreement for Deferral of Construction of Cogeneration Facilities

A general description of these agreements is given below. Specific terms and conditions for these long-term agreements, as well as their associated rate discounts, are detailed in the respective CPUC-approved standard form agreement, or as otherwise provided for in Decision 95-10-033.

1. BUSINESS ATTRACTION AGREEMENT: This agreement is intended solely for customers who are locating or permanently expanding their plant facilities and electrical load within PG&E's service territory. This agreement provides those customers with a declining discount to be applied to PG&E's applicable bundled rate as well as a service connection incentive.

   To qualify for this agreement, a customer must: (1) add at least 4,380,000 kWh/year of new load to PG&E's system, (2) have a designated activity SIC code between 2000-3999 or not be constrained to locate within PG&E's service territory, and (3) sign an affidavit stating that the availability of this agreement is a material factor in its decision to add this load within PG&E's service territory. Qualification under the material factor criterion will require in part that customer's monthly electric costs exceeding, on average, five percent (5%) of its facility's variable operating costs, unless this agreement is to be part of a larger state and local government package to attract its business to California.

   Qualifying customers may sign a six- (6) or ten- (10) year agreement. The declining discount percentages applied to the customer's applicable rate schedule will be 20%, 15%, 10% for the six-year agreement, or 20%, 15%, 15%, 10%, 10% for the ten-year agreement. These discounts will be applied over the first three and five years, respectively, of the agreement's term. As an alternative, a customized discount schedule with a net present value equivalent to the declining discount streams listed above may be developed by the customer. The availability of the Business Attraction Agreement is subject to a maximum participation limit of 100 MW, including participation on all PG&E rate schedules.

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued)

13. CONTRACTS: (Cont'd.)

b. LONG-TERM SERVICE AGREEMENT OPTIONS: (Cont'd.) (T)

2. BUSINESS EXPANSION AND RETENTION AGREEMENT: This agreement is intended to attract incremental load or retain existing load that would, without this agreement, not be able to locate or remain in PG&E's service territory. This agreement is available to PG&E customers who are choosing between an incremental expansion or retention of their manufacturing plant in PG&E's service territory and a comparable, "similarly situated plant" outside of PG&E's service territory. PG&E's capital investment to accommodate the customer's new load under this agreement must be less than twenty-five thousand dollars ($25,000).

To be eligible for this option, a customer must: (1) add or retain at least 4,380,000 kWh/year of eligible load to PG&E's system, (2) have a designated activity SIC code between 2000-3999 or not be constrained to locate within PG&E's service territory, (3) have a similarly situated site that is competing for the load, and (4) sign an affidavit testifying that the availability of this agreement is a material factor in the decision to expand or retain this load at its manufacturing plant in PG&E's service territory. Qualification under the material factor criterion will require, in part, that customer's monthly electric costs exceed, on average, five percent (5%) of its facility's variable operating costs, unless this agreement is to be part of a larger state and local government package to attract its business to California. The availability of the Business Expansion and Retention Agreement is subject to a maximum participation limit of 50 MW, including participation on all PG&E rate schedules.

Qualifying customers may sign a three- (3) or five- (5) year agreement. The initial rate for the customer's eligible load will be equal to the average comparable utility rate in the geographical area where the similarly situated plant is located. The initial rate will be escalated annually by the percent increase, or decrease, of the competing area's average utility rate. Discounted rates will be subject to a Discount Floor price, as defined in Decision 95-10-033.

3. COGENERATION DEFERRAL AGREEMENT: This agreement is intended to defer the construction of customer cogeneration facilities which would uneconomically bypass PG&E's electrical facilities. This agreement is limited to the deferral of ten megawatts (10 MW) of cogenerated power.

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued)

13. CONTRACTS: (Cont'd.)

b. LONG-TERM SERVICE AGREEMENT OPTIONS: (Cont'd.) (T)

3. COGENERATION DEFERRAL AGREEMENT: (Cont'd.)

To qualify for this option, a customer must: (1) have sufficient thermal load to efficiently convert and bypass a minimum of 8,000,000 kWh of usage at its premise each year, (2) demonstrate to PG&E's satisfaction its willingness and ability to perform such a bypass, and (3) sign an affidavit stating that the availability of this agreement is a material factor in its decision to defer the construction of the cogeneration facilities. Only the deferral of the construction of cogeneration facilities that PG&E anticipates will meet state and federal regulatory commission efficiency standards for a "qualifying facility" will qualify customers for this option. The Cogeneration Deferral Agreement is subject to a maximum participation limit of 100 MW including participation on all PG&E rate schedules.

The cogeneration deferral agreement has a five- (5) year term. The rate discount for eligible load will determined by a CPUC-authorized discount matrix. The customer's discounted initial rate represents the average electric rate that would be achieved by the customer's deferred cogeneration facilities. The initial rate shall be escalated annually by the percent increases, or decreases, in the cost of natural gas (40% weighting), and the Consumer Price Index (60% weighting).

In order to qualify for any of these long term agreements:

1) Customer annual usage will be determined using PG&E's billing data from the twelve (12) months immediately preceding the date the customer requests to be considered for service under one of these agreements, if that data is not available or if the customer's operation is expected to significantly change within the next year, PG&E's estimate of the customer's upcoming twelve (12) months of usage;

2) “New load" is defined as load that has not been served on a regular or continuous basis from PG&E distribution, transmission or generation facilities during the twelve (12) months immediately preceding the date the customer requests;

3) PG&E shall determine whether or not the discount under these agreements is a material factor in the customer's decision to locate, retain, or expand its load, or defer construction of its cogeneration facility within PG&E's service territory. However, a customer may contest PG&E's determination by filing a complaint with the CPUC; and

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued)

13. CONTRACTS: (Cont'd.)

b. LONG-TERM SERVICE AGREEMENT OPTIONS: (Cont'd.) (T)

4) A customer may be required to provide business operation information that is relevant to establishing its initial rate level, or verifying its subsequent rate level. The customer shall be responsible for demonstrating, to PG&E's satisfaction, the credibility of all business operation information relevant to establishing or verifying its rate level as it applies to its premise. Information requirements, if any, are outlined in the long term agreements. However, if a customer disagrees with PG&E's conclusion regarding the credibility of any information provided by the customer, the customer may contest PG&E's determining by filing a complaint at the CPUC.

5) If a customer has multiple electrical accounts located on a single premise, PG&E may, at its discretion, aggregate those accounts for the sole purpose of qualifying for these agreements. Aggregated account information shall not be used to create a conjunctively derived bill for the customer's premise.

6) PG&E may, at is sole discretion, disqualify a customer from participating in any one of these long-term options if (1) PG&E believes that the costs to provide adequate transmission and distribution facilities make discounting to a particular customer uneconomic (that is, the customer specific marginal costs exceeds the price for the otherwise applicable schedule), or (2) a customer severely constrains the existing transmission and distribution system in such a way that that customer's marginal costs in the future are expected to be above the price that would otherwise result from the long-term contract option.

All long-term agreement rate discounts apply only to a qualifying customer's eligible load. Therefore, a qualifying customer may have an electric rate discount applied to all or only a portion of its usage at its premise. For the Business Attraction and the Business Expansion and Retention Agreements, discounts will be applied only to electric usage in excess of the customer's prescribed "Base Level" amount. The Base Level shall be equal to PG&E's estimate of the average annual usage at the customer's premise if a long-term agreement was not executed.

For the Cogeneration Deferral Agreement, discounts will only be applied to usage below the customer's "Foundation Level," which is defined in the agreement itself.

Any portion of the customer's load that does not qualify for service under these agreements will be served under this E-20 rate schedule.

All applicable rates, rules, and tariffs shall be remain in force for those customers who sign a long-term agreement. In the event of a conflict, the terms provided within the long term agreement shall supersede those set forth in the standard CPUC-approved tariffs.

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued)

14. BILLING: A customer's bill is first calculated according to the total rates and conditions above. The following adjustments are made depending on the option applicable to the customer. (T)

Bundled Service Customers receive supply and delivery services solely from PG&E. The customer's bill is based on the Total Rate set forth above. The Power Exchange (supply) component is determined by multiplying the average Power Exchange cost for Schedule E-20 for each time period during the last month by the customer's total usage for each time period.

Direct Access Customers purchase energy from an electric service provider continue receiving delivery services from PG&E. The Power Exchange component is determined as specified for a Bundled Service Customer. The bill will be calculated as for a Bundled Service Customer, but the customer will receive a credit for the Power Exchange component. If the Power Exchange component is greater than the amount of the Bundled Service bill, the minimum bill for a Direct Access Customer is zero.

Hourly PX Pricing Option Customers receive supply and delivery services solely from PG&E. A customer taking Hourly PX Pricing Option service must have an interval meter installed at its premise to record hourly usage, since Power Exchange costs change hourly. The bill for a Hourly PX Pricing Option Customer is determined by calculating the bill as if it were a Bundled Service Customer, then crediting the bill by the amount of the Power Exchange component, as determined for Bundled Service and Direct Access Customers, then adding the hourly Power Exchange component which is determined by multiplying the hourly energy used in the billing period by the hourly cost of energy from the Power Exchange.

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued)

14. BILLING: (Cont'd.)

Nothing in this rate schedule prohibits a marketer or broker from negotiating with customers the method by which their customer will pay the CTC charge. (T)

15. CARE DISCOUNT FOR NONPROFIT GROUP-LIVING AND SPECIAL EMLOYEE HOUSING FACILITIES:

Facilities which meet the eligibility criteria in Rule 19.2 or 19.3 are eligible for a California Alternate Rates for Energy discount under Schedule E-CARE. Customers will continue to receive the CARE discount through PG&E regardless of energy service provider. Customers will be billed as described in the BILLING section; and the CARE discount will be determined before any credit for Direct Access service. (T)

16. NON-FIRM BIDDING PILOT PROGRAM:

Customers participating in the Voluntary Non-firm Bidding Pilot Program established by Decision No. 92-11-049, must be winning bidders, as determined by PG&E, and must sign an Agreement for Voluntary Non-firm Bidding Pilot Electric Service (Agreement) (Form No. 79-785). (T)

a. Non-firm Bidding Pilot participants will receive a rate reduction calculated in accordance with the Agreement.

b. PG&E shall from time to time request Non-firm Bidding Pilot participants to curtail their energy use. All such curtailment requests will be called in accordance with the Agreement.

17. LOCAL NON-FIRM BIDDING PILOT PROGRAM:

Customers participating in the Local Non-firm Bidding Pilot Program established by Decision No. 93-01-041, must be winning bidders, as determined by PG&E, and must sign an Agreement for Voluntary Local Non-firm Bidding Pilot Electric Service (Agreement) (Form No. 79-786). (T)

a. Local Non-firm Bidding Pilot participants will receive a rate reduction calculated in accordance with the Agreement.

b. PG&E shall from time to time request Local Non-firm Bidding Pilot participants to curtail their energy use. All such curtailment requests will be called in accordance with the Agreement.

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued)

18. OPTIONAL OPTIMAL BILLING PERIOD SERVICE:

a. Eligibility (T)

On an experimental pilot basis and subject to the availability and installation of solid state recorder equipment, firm service primary and secondary voltage customers whose maximum demand exceeds 1,000 kW for three consecutive billing months may select the "optimal billing period" service on a voluntary as is in up to two "subject" summer months (subject month is defined as the month in which the production cycle starts or ends), one at the start and one at the end of the customer's high seasonal production cycle. The meter read date separating the subject month at the start of production, but precedes it at the end of production) would be redesignated to an alternative read date. In no event shall any revised billing period exceed 45 days nor less than 15 days. The summer season average rate limiter must otherwise apply to the subject month at the start of the customer's high production cycle, but need not apply to the subject month at the end of production or the two adjacent months. The customer would retain the protection of the summer average rate limiter in all summer months, including the revised subject and adjacent months, where the rate limiter is imposed before the additional customer charge in Section 18.c has been included in the calculation. Qualifying customers must have total summer kWh usage that is at least 2.0 times total winter kWh usage for the most recent 12 month period from November 1 through October 31. Customers that discontinue this option may not enroll in this option again for a period of twelve months.

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued)

18. OPTIONAL OPTIMAL BILLING PERIOD SERVICE: (Cont'd.)

b. Customer Notification to PG&E (T)

Upon enrollment, the customer shall notify PG&E of the approximate two months where seasonal production starts and ends. As they occur, the customer shall notify PG&E of the exact seasonal production start and end dates. Upon notification by the customer of a production start date, PG&E will wait until the regular read date to verify that the regular subject month bill would have otherwise invoked the rate limiter. If the rate limiter is invoked for the summer subject start month, the customer will be billed based on the optimal meter read dates or the regular scheduled meter read dates, whichever is the lower bill. Throughout the six month period, customers will receive their regular bill. Approximately two months after the production start or end date, the customer will receive a credit, if one should apply, for the optimal billing period. If a credit does not apply, the customer will not receive additional billing. If the rate limiter does not otherwise apply, the regular bill based on the old read date will be issued, and the customer can then request the special optimal bill option in only one production end date "subject" month. The application of this billing option to a production end date may occur prior to its application to a production start date, such as when a customer has more than one high production cycle. The customer must notify PG&E in writing, via facsimile (fax) to both the PG&E account representative and PG&E's Customer Accounting Department, of the production start or end date within two days of the production start or end date. Customers will receive from PG&E's Customer Accounting Department a fax receipt verification upon notice of a production start or end date. PG&E will notify the customer of the regularly scheduled meter read dates and, upon request, the customer's rate limiter history. The customer must sign an Optimal Billing Period Service Customer Election Form (Form No. 79-842).

c. Customer Charge

Upon enrollment, a special customer charge will be assessed in all summer months to cover the incremental costs of the required solid state recorder, and special program billing, recruitment, and administrative costs. The customer charge shall be $130 per meter per summer month for primary and secondary voltage customers. The customer is obligated to pay this monthly customer charge upon only while enrolled in this option, but any customer that drops out may not enroll in this option for a period of twelve months. Customers who have signed contracts and are awaiting solid state recorders so that they can participate in the program will not be assessed the special customer charge until a solid state recorder has been installed.

For billing purposes, the special customer charge for the optional billing period service shall be assigned to Distribution.

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued)

18. OPTIONAL OPTIMAL BILLING PERIOD SERVICE: (Cont'd.)

d. Proration of Charges (T)

All applicable customer charges, demand charges or other applicable fixed charges, shall be prorated as specified in Rule 9. As specified in Rule 9, Sections A and B, the regular billing period will be once each month, and prorations for monthly bills of less than 27 or more than 33 days shall be calculated on the basis of the number of days in the period in question to the total number of days in an average month, which shall be taken as 30.4 days.

e. Functional Assignment of Credit

For billing purposes, the optional billing credit will be assigned to Generation.

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF1,000 KILOWATTS OR MORE
(Continued)

19. BILLING FOR CUSTOMERS WITHOUT INTERVAL METERS:

All hourly PX pricing option customers and those direct access customers with interval meters will be billed as described in the Rates section above.

All bundled service customers and direct access customers without interval meters will be billed using the Total Rates listed in the Rates section above. Until August 1999, charges for each function will be determined by applying the following functional percentages to the total charge:

Firm Service—Transmission Voltage Level:

Transmission	Distribution	Public Purpose Programs	Generation	Nuclear Decommissioning
2.973% (R)	4.955%	3.617%	88.050% (I)	0.405%

Firm Service—Primary Voltage Level:

Transmission	Distribution	Public Purpose Programs	Generation	Nuclear Decommissioning
3.790% (R)	14.555%	3.638%	77.579% (I)	0.438%

Firm Service—Secondary Voltage Level:

Transmission	Distribution	Public Purpose Programs	Generation	Nuclear Decommissioning
7.653% (R)	23.825%	3.617%	64.456% (I)	0.449%

Nonfirm Service—Transmission Voltage Level:

Transmission	Distribution	Public Purpose Programs	Generation	Nuclear Decommissioning
3.763% (R)	6.272%	4.578%	84.875% (I)	0.512%

Nonfirm Service —Primary Voltage Level:

Transmission	Distribution	Public Purpose Programs	Generation	Nuclear Decommissioning
4.543% (R)	17.442%	4.360%	73.130% (I)	0.525%

Nonfirm Service —Secondary Voltage Level:

Transmission	Distribution	Public Purpose Programs	Generation	Nuclear Decommissioning
8.991% (R)	27.986%	4.249%	58.246% (I)	0.528%

Generation charge is calculated based on the total charge less the sum of: Distribution, Transmission, Public Purpose Programs, and Nuclear Decommissioning. CTC is calculated residually by subtracting the Power Exchange component minus the amount of the FTA charge (if applicable) as set forth in the Rates section above. For nonfirm customers, the Firm Service percentages will be applied to the customer's Firm Service Level charges. The nonfirm percentages will be applied to the nonfirm portion of the customer's bill.

(Continued)

SCHEDULE S—STANDBY SERVICE

APPLICABILITY: PG&E will supply electricity and capacity on a standby basis under the terms of this schedule for customers: (1) whose supply requirements would otherwise be delivered through PG&E-owned facilities (including Independent System Operator (ISO)-controlled transmission facilities) but are regularly and completely provided through facilities not owned by PG&E; (2) who at times take auxiliary service (by means of a double-throw switch) from another public utility; (3) who require PG&E to provide reserve capacity and stand ready at all times to supply electricity on an irregular or noncontinuous basis; or (4) whose nonutility source of generation does not qualify under items (1), (2), or (3) above, but who qualify for and elect to receive back-up service under the provisions of Special Condition 7 below.

Customers whose premises are: (1) supplied only in part by electric energy from a nonutility source of supply, and who do not qualify for or elect to take back-up service under the provisions of Special Condition 7, and/or (2) whose regular non-utility source of supply is subject to an extended outage as defined under Special Condition 9, will receive service under one of PG&E's other applicable rate schedules. However, this service will be provided subject to the provisions of Special Conditions 1 through 6 and 8 through 10 below, and reservation charges as specified under Section 1 will also be applicable.

TERRITORY: PG&E's entire service territory.

RATES:

1. SECONDARY	Transmission	Distribution	Public Purpose Programs	Generation	Nuclear Decom-missioning	Total Rate
Reservation Charge (per kW per month applied to 85 percent of the Reservation Capacity)	$0.95 (R)	$1.56	–	$0.04 (I)	–	$2.55
Energy Charges (per kWh)						
Peak-Period						
Summer	–	$0.11433	$0.00437	$0.27232	$0.00057	$0.39159
Winter	–	–	–	–	–	–
Part-Peak-Period						
Summer	–	$0.03401	$0.00437	$0.07753	$0.00057	$0.11648
Winter	–	$0.03004	$0.00437	$0.06793	$0.00057	$0.10291
Off-Peak-Period						
Summer	–	$0.01254	$0.00437	$0.02548	$0.00057	$0.04296
Winter	–	$0.01602	$0.00437	$0.03393	$0.00057	$0.05489
Transmission Revenue Balancing Account Adjustment Rate per kWh per month	($0.00017)	–	–	$0.00017	–	$0.00000
Nonfirm Credits (per kWh)						
On-Peak Energy	–	–	–	$0.01873	–	$0.01873
Part-Peak Energy	–	–	–	$0.00187	–	$0.00187
UFR Credit	–	–	–	$0.00091	–	$0.00091
Reactive Demand Charge (per kVAR of maximum reactive demand)	–	–	–	$0.15	–	$0.15

(Continued)

SCHEDULE S—STANDBY SERVICE
(Continued)

RATES:
(Cont'd.)

2. PRIMARY	Transmission	Distribution	Public Purpose Programs	Generation	Nuclear Decom-missioning	Total Rate
Reservation Charge (per kW per month applied to 85 percent of the Reservation Capacity)	$0.29 (R)	$1.95	–	$0.31 (I)	–	$2.55
Energy Charges (per kWh)						
Peak-Period						
Summer		–	$0.00819	$0.35701	$0.00112	$0.36632
Winter	–	–	–	–	–	–
Part-Peak-Period						
Summer	–	–	$0.00819	$0.09883	$0.00112	$0.10814
Winter	–	–	$0.00819	$0.08542	$0.00112	$0.09473
Off-Peak-Period						
Summer	–	–	$0.00819	$0.02981	$0.00112	$0.03912
Winter	–	–	$0.00819	$0.04065	$0.00112	$0.04996
Transmission Revenue Balancing Account Adjustment Rate per kWh per month	($0.00017)	–	–	$0.00017	–	$0.00000
Nonfirm Credits (per kWh)						
On-Peak Energy	–	–	–	$0.01873	–	$0.01873
Part-Peak Energy	–	–	–	$0.00187	–	$0.00187
UFR Credit	–	–	–	$0.00091	–	$0.00091
Reactive Demand Charge (per kVAR of maximum reactive demand)	–	–	–	$0.15	–	$0.15

(Continued)

SCHEDULE S—STANDBY SERVICE
(Continued)

RATES:
(Cont'd.)

3. TRANSMISSION	Transmission	Distribution	Public Purpose Programs	Generation	Nuclear Decom-missioning	Total Rate
Reservation Charge (per kW per month applied to 85 percent of the Reservation Capacity)	$0.35	–	–	–	–	$0.35
Energy Charges (per kWh)						
Peak-Period						
Summer	$0.00627 (R)	$0.07010	$0.00283	$0.22213 (I)	$0.00035	$0.30168
Winter	–	–	–	–	–	–
Part-Peak-Period						
Summer	$0.00124 (R)	$0.01383	$0.00283	$0.04129 (I)	$0.00035	$0.05954
Winter	$0.00148 (R)	$0.01658	$0.00283	$0.05012 (I)	$0.00035	$0.07136
Off-Peak-Period						
Summer	$0.00083 (R)	$0.00933	$0.00283	$0.02680 (I)	$0.00035	$0.04014
Winter	$0.00104 (R)	$0.01160	$0.00283	$0.03412 (I)	$0.00035	$0.04994
Transmission Revenue Balancing Account Adjustment Rate						
per kWh per month	($0.00017)	–	–	$0.00017	–	$0.00000
Nonfirm Credits (per kWh)						
On-Peak Energy	–	–	–	$0.01873	–	$0.01873
Part-Peak Energy	–	–	–	$0.00187	–	$0.00187
UFR Credit	–	–	–	$0.00091	–	$0.00091
Reactive Demand Charge (per kVAR of maximum reactive demand)	–	–	–	$0.15	–	$0.15

Generation charge is calculated based on the total rate less the sum of: Distribution, Transmission, Public Purpose Program, Nuclear Decommissioning, and FTA (where applicable) charges. CTC is calculated residually by subtracting the PX charge as calculated in Schedule PX from the generation charge.

(Continued)

SCHEDULE S—STANDBY SERVICE
(Continued)

RATES (Cont'd.)

4. Meter and Customer Charges:*
($/meter/month)

Customer Class	Customer Charge	TOU, Nonfirm or Load Profile Meter Charge
Residential	$5.00	$3.90
Agricultural	$16.00	$6.00
Small Light and Power (Reservation Capacity ≤ 50 kW)		
Single Phase Service	$8.10	$6.80
PolyPhase Service	$12.00	$6.80
Medium Light and Power (Reservation Capacity > 50 kW and < 500 kW)	$75.00	$6.00
Medium Light and Power (Reservation Capacity ≥ 500 kW and < 1000 kW)		
Transmission	$610.00	–
Primary	$140.00	–
Secondary	$175.00	–
Large Light and Power (Reservation Capacity ≥ 1000 kW)		
Transmission	$715.00	–
Primary	$310.00	–
Secondary	$385.00	–
NonFirm		
Curtailable	–	$190.00
Interruptible	–	$200.00
Supplemental Standby Service Meter Charge	–	$186.00

* All Meter and Customer charges, except for nonfirm meter charges which are assigned to generation, are assigned to distribution. (N)
(N)

(Continued)

SCHEDULE S—STANDBY SERVICE
(Continued)

RATES: (Cont'd.)

5. TYPES OF CHARGES: The customer's monthly charge for service under Schedule S is the sum of the Reservation, Energy, Customer, and TOU Meter Charges.

- The **Reservation Charge**, in dollars per kilowatt (kW), applies to the customer's Reservation Capacity, as defined in Special Condition 1.
- The **Energy Charge** will be either a flat Energy Charge or the sum of the time-of-use (TOU) Energy Charges times the customer's energy use. The customer's Standby Agreement (Form 79-285) will specify whether the flat or TOU Energy Charges apply. All customers whose Reservation Capacity exceeds 499 kW must pay the TOU energy charges. TOU periods are defined in Section 7 below. Flat Energy Charges are available only until a TOU meter can be installed. No flat Energy Charges will be available after April 30, 1994.
- The **Customer Charge** will be paid monthly by all nonresidential customers. Residential customers will pay a Customer Charge only in those months when the Customer Charge exceeds the customer's bill under Schedule S.

  The Customer Charge varies by class of service, Reservation Capacity, and Voltage Level (for customers with Reservation Capacity greater than 499 kW).
- The **TOU Meter Charge** applies to Residential, Agricultural, and Small and Medium Light and Power customers, with Reservation Capacity less than 500 kW, who chose to have a TOU meter installed. This charge will be paid in addition to the monthly Customer Charge.
- The **Nonfirm Meter Charge** applies to customers whose Reservation Capacity is greater than 499 kW and receive service under the nonfirm service option. This charge will be paid in addition to the monthly customer charge.

The **Load Profile Meter Charge** applies to customers electing to receive the back-up and maintenance portions of their total service requirements under the provisions of Special Condition 7. This charge will be paid in addition to the regular Schedule E-19, Schedule E-20, or Schedule E-26 monthly customer charge. (T)

(Continued)

SCHEDULE S—STANDBY SERVICE
(Continued)

RATES: (Cont'd.)

6. DEFINITION OF SERVICE VOLTAGE: (L)

The following defines the three voltage classes of Schedule S rates. Standard Service Voltages are listed in Rule 2*.

a. Secondary: This is the voltage class if the service voltage is less than 2,400 volts or if the definitions of "primary" and "transmission" do not apply to the service.

b. Primary: This is the voltage class if the customer is served from a "single customer substation" or without transformation from PG&E's serving distribution system at one of the standard primary voltages specified in PG&E's Electric Rule 2, Section B.1.

c. Transmission: This is the voltage class if the customer is served without transformation at one of the standard transmission voltages specified in PG&E's Electric Rule 2, Section B.1. (L)

The Standby Reservation Charges for customers who have paid for the total cost of the service transformers as special facilities under electric Rule 2 are determined by the voltage at the high side of the service transformer. All other charges will be billed on the voltage level at the low side of the service transformer.

PG&E retains the right to change its line voltage at any time, after reasonable advance notice to any customer affected by the change. The customer then has the option of changing its system to receive service at the new line voltage or accepting service at the initial voltage level through transformers supplied by PG&E.

(L)

* The Rules referred to in this rate schedule are part of PG&E's electric tariffs. Copies are available at PG&E's local offices.

(Continued)

SCHEDULE S—STANDBY SERVICE
(Continued)

RATES:
(Cont'd.)

7. DEFINITION OF TIME PERIODS:

Times of the year and times of the day are defined as follows:

SUMMER Period A (service from May 1 through October 31):

Peak:	12:00 noon to 6:00 p.m.	Monday through Friday (except holidays)
Partial-Peak:	8:30 a.m. to 12:00 noon AND 6:00 p.m. to 9:30 p.m.	Monday through Friday (except holidays)
Off-Peak:	9:30 p.m. to 8:30 a.m.	Monday through Friday
	All Day	Saturday, Sunday, and holidays

WINTER Period B (Service from November 1 through April 30):

Partial-Peak:	8:30 a.m. to 9:30 p.m.	Monday through Friday (except holidays)
Off-Peak:	9:30 p.m. to 8:30 a.m.	Monday through Friday (except holidays)
	All Day	Saturday, Sunday and holidays

HOLIDAYS: "Holidays" for the purposes of this rate schedule are New Year's Day, President's Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas Day. The dates will be those on which the holidays are legally observed.

8. NONFIRM SERVICE:

A Customer who elects to receive non-firm service under Schedule S must participate in PG&E's emergency curtailment program. A non-firm service customer may also elect to participate in PG&E's underfrequency relay (UFR) and "economic dispatch" programs. Please note that PG&E may require up to three years' written notice for a change from non-firm to firm service, or for termination of participation in the underfrequency relay program.

a. ELIGIBILITY: To qualify for non-firm service under Schedule S, the customer must demonstrate to PG&E's satisfaction that it has at least 500 kW of average peak-period on-site load, whether served by PG&E or by its own generator.

(Continued)

SCHEDULE S—STANDBY SERVICE
(Continued)

RATES: (Cont'd.)

8. NONFIRM SERVICE: (Cont'd.)

b. PRE-EMERGENCY CURTAILMENT REQUIREMENTS: A customer may be requested to curtail, on a pre-emergency basis, up to five times per year. Each pre-emergency curtailment will last no more than five hours.

Customers will be given at least 30 minutes notice before each curtailment. PG&E will request at least six pre-emergency curtailments during any rolling three-year period. The pre-emergency curtailments will be requested subject to the criteria listed in Section 8.d below. (T)

Customers participating in the Under-Frequency Relay (UFR) Program will be subject to a maximum of three pre-emergency curtailments per year and to at least three pre-emergency curtailments during any rolling three-year period. Automatic UFR operations shall not be included in annual pre-emergency or emergency curtailment limits.

No pre-emergency curtailments will be called for any non-firm customer if there have been two or more emergency or pre-emergency curtailments to date during the year; unless additional pre-emergency curtailments are necessary to meet the minimum requirement of six pre-emergency curtailments during a rolling three-year period.

c. PRE-EMERGENCY CURTAILMENT PROCEDURE: PG&E will notify the customer by telephone, electronic mail, or other reliable means of communication. This notification will designate the time by which the customer's kW demand must be completely curtailed.

d. EMERGENCY CURTAILMENT PROCEDURE: When it becomes necessary for PG&E to request a curtailment, PG&E will notify the customer by telephone, electronic mail, or other reliable means of communication. This notification will designate a time by which the customer's kW demand must be completely curtailed.

The customer may not resume the use of curtailed power until notified by PG&E that it may do so or until the customer has curtailed its service for six hours.

e. LIMIT ON EMERGENCY CURTAILMENTS: A customer will be requested to curtail demand, under the emergency curtailment program, no more than 30 times per year and will be given at least 30 minutes notice before each curtailment. Curtailments will not exceed six hours for any individual interruption or 100 hours for the entire year.

(Continued)

SCHEDULE S—STANDBY SERVICE
(Continued)

RATES:
(Cont'd.)

8. NONFIRM SERVICE: (Cont'd.)

f. EMERGENCY-NOTICE PROVISION: If there is an emergency on the PG&E system, PG&E may ask the customer to curtail the use of electricity on less than the 30 minute notice allowed for the non-firm service option. The customer will be asked to make its best effort to comply. The customer will not be assessed the noncompliance penalty for failing to comply within the shorter notice period, but the customer will be assessed this penalty if the regular notice period for the option passes and the customer still has not curtailed use.

g. NONCOMPLIANCE PENALTY: If PG&E requests that a non-firm service customer curtail the use of electricity and the customer fails to do so by the time specified, the customer must pay a noncompliance penalty. This penalty will be payable in addition to the regular charges.

The penalty will be calculated by determining the total amount of energy taken during the curtailment period and multiplying this total by $8.40 per kWh, subject to a 200 percent annual cap on the total penalty as described below.

In any given calendar year, the noncompliance penalties may not exceed 200 percent of the annual incentive level. The noncompliance penalty limit is equal to twice the annual incentive paid (the difference between what the customer would have paid on firm service rates less the customer's bill on nonfirm rates excluding noncompliance penalties). If a customer's total noncompliance penalties in any given year exceed the noncompliance penalty limit, PG&E shall bill the customer a noncompliance penalty equal to the noncompliance penalty limit.

h. TELEPHONE LINE REQUIREMENTS: Non-firm customers are required to make available a telephone line and space for a notification printer. This requirement is in addition to any other equipment requirement which may apply.

i. COMMUNICATION CHANNEL FOR UFR SERVICE: UFR program customers are required to provide an exclusive communication channel from the PG&E-provided terminal block at the customer's facility to a PG&E-designated control center. The communication channel must meet PG&E's specifications, and must be provided at the customer's expense. PG&E shall have the right to inspect the communication circuit upon reasonable notice.

j. BILL REDUCTIONS FOR NON-FIRM SERVICE CUSTOMERS: If a customer elects this Schedule S service option, the credits shown under Section 2 of this Schedule will apply to all usage during the on-peak and part- peak billing period. Should the customer also elect service under an underfrequency relay (UFR option), the additional credit shown for underfrequency relay service shall apply to all energy usage.

(Continued)

SCHEDULE S—STANDBY SERVICE
(Continued)

SPECIAL CONDITIONS:

1. RESERVATION CAPACITY: The Reservation Capacity to be used for billing under the above rates shall be as set forth in the customer's contract for service. For new or revised contracts, the Reservation Capacity shall be determined by the customer. However, if the customer's standby demand exceeds this contracted capacity in any billing month, that standby demand shall become the new Reservation or Contract Capacity for 36 months, beginning with that month. See Special Condition 8 for the definition of Reservation Capacity for Supplemental Standby Service customers.

2. REACTIVE DEMAND CHARGE: When the customer's plant (or other source) is operated in parallel with PG&E's system, the customer will design and operate its facilities so that the reactive current requirements of the portion of the customer's load supplied from the customer's plant (or other source) are not supplied at any time from PG&E's system. If the customer places a reactive demand on PG&E's system in any month in excess of 0.1 kilovolt-ampere reactive (kVAR) per kW of Reservation Capacity, then a Reactive Demand Charge will be added to the customer's standby bill, except as specified below for customers operating synchronous generators under net sales contracts. This additional charge will be equal to the largest measured number of kVAR created by the generator during any time of its past operation times the current Reactive Demand Charge. This Reactive Demand Charge will be subsequently applied to the customer's monthly bill until the customer demonstrates to PG&E's satisfaction that adequate correction has been provided.

   For customers operating synchronous generators under net sale contracts, reactive demand in excess of 0.1 kVAR per kW of station generation capability will be used in determining applicability of the Reactive Demand Charge, rather than customer current Reservation Capacity.

3. REDUCED CUSTOMER CHARGE: Standby customers whose Reservation Capacity is less than 500 kW may qualify for a reduced Customer Charge. The following monthly Customer Charges apply to customers who own or pay special facilities charges pursuant to Rule 21 for all of the interconnection facilities in place for PG&E to provide service to them:

Small Light and Power (Reservation Capacity ≤ 50 kW)	$6.60
Medium Light and Power (Reservation Capacity > 50 kW and < 500 kW)	$56.60
Medium Light and Power (Reservation Capacity > 500 kW and < 1000 kW served at primary and secondary voltages)	$56.60

(Continued)

SCHEDULE S—STANDBY SERVICE
(Continued)

SPECIAL CONDITIONS: (Cont'd.)

4. PARALLEL OPERATION: Any customer may operate its generating plant in parallel with PG&E's system if the customer's plant is constructed and operated in accordance with Rule 21. However, a customer who operates its plant in parallel must assume responsibility for protecting PG&E and other parties from damage resulting from negligent operation of the customer's facilities. Customers may be required to meet requirements imposed by other governing entities having jurisdiction over PG&E's transmission lines including the ISO and the Western Systems Coordinating Council. The customer shall provide, own, install, and maintain all facilities necessary to accommodate any metering equipment specified by PG&E. Meters shall not allow reverse registration. (T) | | (T)

5. CONTRACT: This schedule is applicable only on a one-year contract (Form No. 79-285). Once the initial one-year term is over, the contract will automatically continue in effect for successive terms of one year each until it is cancelled. Either party may cancel the contract by giving written notice not less than 30 days prior to the end of the current term. If the customer at any time increases the capacity of a load connected to its plant (or other source), the customer shall promptly notify PG&E. Any revision to the Reservation Capacity shall then be redetermined to be applicable beginning in the month in which such increase occurs.

6. LIMITATION ON RESERVATION CAPACITY SERVED: Standby service to new or increased loads is limited to PG&E's ability to serve such loads without jeopardizing service to existing customers on rate schedules for firm service, including standby service. If standby service to any load or combination of loads is refused by PG&E, PG&E shall notify the California Public Utilities Commission (Commission) in writing. Standby service will require a special contract which shall be subject to approval of the Commission in the following cases:

   a. Reservation Capacity exceeds 100,000 kW per account;

   b. The combined Reservation Capacity for two or more customers whose other power source is a single, nonutility plant, exceeds 100,000 kW;

   c. The service is of an unusual character, as determined by PG&E.

(D) | | | | | | | (D)

(Continued)

SCHEDULE S—STANDBY SERVICE
(Continued)

SPECIAL CONDITIONS: (Cont'd.)

7. SUPPLEMENTAL STANDBY SERVICE (BACKUP REQUIREMENTS): (T)

a. Schedule E-19, Schedule E-20 or Schedule E-25 customers whose nonutility source of generation does not regularly supply all the power necessary at their premises may elect to receive the back-up portion of their total service requirement under Schedule S if 1) the rated capacity of the customer's on-site generator is at least 50 percent of the customer's maximum kW demand, and 2) load profile recorders are installed to separately to meter the net on-site generation and the on-site load. Supplemental standby service will be available to all Schedule E-19 or Schedule E-20 customers whose nonutility source of generation does not regularly supply all the power necessary at their premises, if load profile recorders are installed to separately to meter the net on-site generation and the on-site load, effective May 1, 1994. If the customer elects instead to receive all of their service under Schedule E-19 or E-20, however, Special Conditions 1 through 6 of this Schedule will apply to the back-up portion of their load, with a Reservation capacity as determined by the net capacity of the on-site generation. (T)

b. Supplemental standby service requires the installation of a load profile recorder. PG&E will install load profile recorders, subject to meter availability. The customer shall provide, install, own, and maintain all facilities necessary to accommodate metering equipment specified by PG&E. An additional charge applies for Supplemental Standby Service. A Supplemental Standby Service Meter Charge will be added to the standby customers bill in addition to the TOU Energy Charges for back-up requirements, specified in the Rates Section. Supplemental standby service customers will also pay the appropriate rate Schedule E-19 or E-20 charges, including the Customer Charge, for their supplemental power use.

(Continued)

SCHEDULE S—STANDBY SERVICE
(Continued)

SPECIAL CONDITIONS: (Cont'd.)

7. SUPPLEMENTAL STANDBY SERVICE (BACKUP REQUIREMENTS): (Cont'd.) (T)

c. Back-up requirements are the portion of the customer's maximum demand and energy usage in any billing month caused by the nonoperation of the customer's alternative source of power. The customer's Reservation Capacity shall be determined by the net capacity of the customer's on-site generation, calculated as the average gross continuous full load capability of the generator during the hours between 10:00 a.m. and 8:00 p.m. of the winter part-peak period, less all auxiliary loads. During the winter season, supplemental loads are any on-site loads in excess of the Reservation Capacity.

During the summer season, supplemental loads are any on-site loads in excess of the Reservation Capacity, minus the customer's Summer Season Operating Capacity Adjustment. The customer's Summer Season Operating Capacity Adjustment shall be calculated as the difference between the average gross continuous full load capability during the hours between 10:00 a.m. and 8:00 p.m. of the winter part-peak period and the average gross continuous full load capability during the same hours of the summer season. The customer's Reservation Capacity and Summer Season Operating Capacity Adjustment are both subject to annual revision based upon review of recorded operating data for the customer's generation. Back-up requirements will be billed under Schedule S, while supplemental loads will be billed under the provisions of the customer's otherwise applicable rate schedule.

The customer's metered reactive power usage will be prorated for the purpose of assigning such usage separately to the customer's bills for backup power and for supplemental power. In particular, a single Power Factor Adjustment (as specified under Special Condition 8) will be (T) calculated based on the ratio of all kWh and kVAh used, and then applied separately to the customer's bills for backup and supplemental power. The Reactive Demand Charge (see Special Condition 2) will be calculated by multiplying the customer's maximum measured reactive demand by the ratio of the current Reservation Capacity and the customer's maximum total kW of backup and supplemental load.

(Continued)

SCHEDULE S—STANDBY SERVICE
(Continued)

SPECIAL CONDITIONS: (Cont'd.)

8. POWER FACTOR ADJUSTMENT: When the customer's Reservation Capacity is greater than 400 kW, the bill will be adjusted based on the power factor. The power factor is derived from the ratio of kWh to kVAh consumed in the month. Power factors are averaged and rounded to the nearest whole percent. (T)

The rates in this rate schedule are based on a power factor of 85 percent. If the average power factor is greater than 85 percent, the total monthly bill, excluding any taxes will be reduced by 0.06 percent for each percentage point above 85 percent. If the average power factor is less than 85 percent, the total monthly bill, excluding any taxes will be increased by 0.06 percent for each percentage point below 85 percent.

The power factor adjustment will be assigned to generation for billing purposes.

The customer shall pay only the greater of the power factor adjustment and the reactive demand charge.

Generators for which ISO standards apply must also meet power factor (N)
requirements specified in the ISO tariff. (N)

9. EXTENDED OUTAGES: If a customer's generation equipment or alternative supply source is subject to an extended outage, and this outage is expected to persist for at least one complete regular billing cycle, the customer may request alternate billing under the terms of that otherwise-applicable, demand-metered regular service tariff indicated by the customer's current reservation capacity, by providing formal written notification to PG&E. Billing under the indicated otherwise-applicable schedule would begin with the customer's first regular meter read date after the beginning of the outage. After PG&E is notified that the generation equipment has been returned to service, billing under Schedule S will resume as of the last regular meter read date that has preceded resolution of the outage. In the interim, reservation charges as specified under Section 1 of this tariff would continue to apply to the customer's bill, in addition to all charges from the indicated otherwise-applicable tariff. (T)

10. NON-TIME-OF-USE METERING: In those cases where PG&E deems it is not cost-effective to install a time-of-use (TOU) meter, PG&E will estimate the customer's kWh usage for each TOU period, and apply all TOU charges to the estimated kWh usage by TOU period. PG&E will estimate the customer's total kWh usage in the billing period to kWh usage within each TOU period based on a percentage breakdown using the ratio of the number of hours in each TOU period to total hours in the billing period. (T)

(Continued)

SCHEDULE S—STANDBY SERVICE
(Continued)

BILLING: A customer's bill is first calculated according to the total rates and conditions above. The following adjustments are made depending on the option applicable to the customer. (N)

Bundled Service Customers receive supply and delivery service solely from PG&E. The customer's bill is based on the Total Rate set forth above. The Power Exchange (supply) component is determined by multiplying the average Power Exchange cost for Schedule S for each time period during the last month by the customer's total usage for each time period.

Direct Access Customers purchase energy from an energy service provider and continue receiving delivery services from PG&E. The Power Exchange component will be determined as specified for a Bundled Service Customer. The bill will be calculated as for a Bundled Service Customer, but the customer will receive a credit for the Power Exchange component. If the Power Exchange component is greater than the amount of the Bundled Service bill, the minimum bill for a Direct Access Customer is zero.

Hourly PX Pricing Option Customers receive supply and delivery service solely from PG&E. A customer taking Hourly PX Pricing Option service must have an interval meter to record hourly usage since Power Exchange costs change hourly. The bill for a Hourly PX Pricing Option Customer is determined by calculating the bill as if it were a Bundled Service Customer, then crediting the bill by the amount of the Power Exchange component, as determined for Bundled Service and Direct Access Customers, then adding the hourly Power Exchange component which is determined by multiplying the hourly energy used in the billing period by the cost of energy from the Power Exchange. (N)

Nothing in this rate schedule prohibits a marketer or broker from negotiating with customers the method by which their customer will pay the CTC charge.

SCHEDULE S—STANDBY SERVICE
(Continued)

BILLING FOR CUSTOMERS WITHOUT INTERVAL METERS:

All hourly PX pricing option customers and those direct access customers with interval meters will be billed as described in the Rates section above.

All bundled service customers and direct access customers without interval meters will be billed using the Total Rates listed in the Rates section above. Until August 1999, charges for each function will be determined by applying the following functional percentages to the total charge:

Transmission Voltage Level:

Transmission	Distribution	Public Purpose Programs	Generation	Nuclear Decommissioning
13.093% (R)	23.593%	3.687%	59.174% (I)	0.453%

Primary Voltage Level:

Transmission	Distribution	Public Purpose Programs	Generation	Nuclear Decommissioning
7.200% (R)	51.172%	3.313%	37.862% (I)	0.453%

Secondary Voltage Level:

Transmission	Distribution	Public Purpose Programs	Generation	Nuclear Decommissioning
6.964% (R)	36.361%	3.476%	52.746% (I)	0.453%

Generation charge is calculated based on the total charge less the sum of: Distribution, Transmission, Public Purpose Programs and Nuclear Decommissioning. CTC is calculated residually by subtracting the Power Exchange component minus the amount of the FTA charge (if applicable) as set forth in the Rates section above.

(Continued)